Maine Public Utilities Commission
Study of Northern Maine Connections
to the New England Grid
Docket No. 97-586

Competition and Market Power in the Northern Maine Electricity Market

-- Draft: For Review Only--

Prepared for the
Maine Public Utilities Commission

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The findings, conclusions, recommendations and errors in this report are the responsibility of the authors.

1. Introduction and Summary

Background

The Maine Legislature recently signed into law a restructuring statute designed to promote effective retail competition in the state's electricity generation market.[1] The Legislature has also directed the Department of the Attorney General (Department) and the Public Utilities Commission (Commission) to conduct jointly a study of market power issues that may arise as a consequence of the restructuring law.[2] The Commission and the Department released an interim market power report in February 1998. The final report is due by the end of 1998.

In addition, the Legislature directed the Commission to investigate the unique conditions and market power concerns of the electricity market in northern Maine.[3] The utilities in northern Maine are not connected to other Maine utilities, and are not a member of the New England Power Pool (NEPOOL), and therefore face greater obstacles to developing a sufficiently competitive electricity generation market. The Commission issued a notice of inquiry (NOI) on this topic in January 1998 (Docket 97-586).

The purpose of this report is to inform the Commission and the Department about the potential for establishing an effectively competitive electricity generation market in northern Maine. The results of this report will be used as input to statewide market power report currently being prepared by the Commission and the Department.

There are a number of factors that indicate that market power could be a significant problem in northern Maine, including:

- There is small number of power plants located within northern Maine, and only three companies own them, or have entitlements to them.
- The divestiture of the Maine Public Service Company (MPS) generation assets to WPS Power Development, as proposed, will not increase the number of generation owners in northern Maine. (However, it will provide other companies with access to the power from the Wheelabrator-Sherman facility).
- The region is not interconnected with any neighboring utilities except for New Brunswick Power Company (NBP). This limits the number of competitive generation companies that can serve northern Maine.
- NBP has the ability to exploit its dominant role with regard to transmission in the region. NBP is not currently regulated and has the flexibility to unilaterally increase or decrease its transmission rates.

[1] P.L. 1997 ch.316, much of which is codified at 35-A M.M.S.A. §§ 3201-3217.

[2] P.L. 1997 ch. 447 Part B.

[3] 35-A M.M.S.A §§ 3206.

- NBP's current transmission tariffs require that generation companies seeking to wheel power through NBP to northern Maine must pay higher transmission prices than those paid by NBP.
- NBP's transmission pricing flexibility has a chilling effect on transmission options in the region. Increasing the transmission price would further limit the ability of new generation companies to reach northern Maine. Reducing the price would reduce the economic benefits to a third party of building a new transmission line to northern Maine.
- Hydro-Québec (HQ) is not willing to sell power into the northern Maine market, due to the high NBP wheel-through tariff.
- Generation companies located in New England will have to overcome transmission stability constraints that limit the amount of firm power that can be transmitted from the south to the north on the Maine Electric Power Company (MEPCO) transmission line -- the only transmission line currently running between New England and NBP.
- Generation companies in New England are reluctant to sell power into the northern Maine market, due to the high NBP wheel-through tariff and the MEPCO transmission constraints.
- Electricity customers in northern Maine do not have access to a competitive wholesale electricity market, denying them of the benefits of an ISO and a competitive spot market.

However the conditions in the region are changing in some ways that may help to mitigate some market power concerns. For example:

- TransEnergy US, a subsidiary of Hydro-Québec, is investigating the option of constructing a transmission line that would connect HQ with MPS.
- Bangor Hydro Electric Company (BHE) has developed plans and obtained permits for a new transmission line connecting it to NBP, creating an alternative to the MEPCO line for delivering power from New England to NBP.
- Two private developers are in the process of constructing new gas-fired power plants in New Brunswick, with the intent of selling the power to US markets.
- NBP has created a Tie Line Interruption Service that can provide back-up power to mitigate the south-to-north constraint on the MEPCO line.
- The new transmission line between BHE and NBP might help mitigate the south-to-north constraint on the MEPCO line. A transmission tap into the MEPCO line by the Bowater paper company might also help mitigate the south-to-north constraint on the MEPCO line.

Framework of Our Analysis

Our analysis begins with an overview of the generation and transmission conditions in northern Maine. We then assess the amount of market concentration in the northern

Maine region, with the use of the Herfindahl-Hirschman Index (HHI). The HHIs indicate that there is currently a very high degree of market concentration in northern Maine, and that adverse market power effects are likely. Most of the market concentration is due to NBP's influence over transmission in the region.

We then identify a set of strategies that could be used to mitigate the market power concerns in northern Maine. We note that accessing a competitive wholesale electricity market -- including a competitive spot market, an Independent System Operator (ISO), and open-access, non-discriminatory transmission services -- is necessary to mitigate market power concerns in northern Maine to an acceptable level.

Table 1.1 describes the framework we used to assess strategies to mitigate market power. We evaluate the following four general strategies that could provide opportunities for reducing the market power concerns in northern Maine:

1. Increase the amount of competition within northern Maine.
2. Increase the amount of competitive generation available from New Brunswick.
3. Increase the amount of competitive generation available from Québec.
4. Increase the amount of competitive generation available from New England.

Table 1.1 Framework For Assessing Options to Mitigate Market Power in Northern Maine

Source of Competitive Generation	**Northern Maine**	**New Brunswick**	**Hydro-Québec**		**New England**	
Transmission Access to Reach Northern Maine	None needed	NBP Line	NBP Line	New Line from HQ to MPS	NBP Line	New Line from MEPCO to MPS
Potential for Competitive Wholesale Market	Very Limited	Very Unlikely	Unlikely	Unlikely	Likely	Likely
Likely Number of Competitors	Four	Five or more	Six or more	Six or more	Many	Many
Herfindahl Index for Northern Maine	2397-2933	1727	1727	2157	1460-1727	1526-2157
Transmission Cost to Reach Northern Maine	None	24 $/kW-year	34 $/kW-year	32-48 $/kW-year	34 $/kW-year	23-35 $/kW-year
Actions Necessary to Mitigate Market Power	1	2 and 3	3 and 4	4 and 5	3, 6 and 8	6, 7 and 8

Actions necessary to mitigate market power:

1. Increase the number of generators located within northern Maine.
2. Make the wholesale market in New Brunswick more competitive.
3. Convince NBP to provide open-access, non-discriminatory firm transmission capacity.

4. Make the wholesale market in Québec more competitive.
5. Build a new transmission line between Hydro-Québec and MPS.
6. Resolve the south-to-north constraint on the MEPCO transmission line.
7. Build a new transmission line between MPS and MEPCO.
8. Encourage distribution companies in northern Maine to become members of the ISO-NE.

Conclusions

It is clear that under current conditions the electricity market in northern Maine is likely to be subject to market power problems. While some of the market power issues can be mitigated by the strategies and options discussed in the study, the greatest cause of market power concern -- New Brunswick Power -- poses a significant challenge. The role of NBP in the area cannot be overstated. It has the ability to exploit its role as the only provider of transmission into northern Maine, thereby limiting the amount of competitive generation suppliers that can reach the area. Not only does it have control over all of the existing transmission into northern Maine, it could also play an influential role in assisting or hindering many of the solutions that we have considered in this study.

Our analysis indicates that the only scenarios where market concentration is reduced to acceptable levels are those where NBP's market dominance is reduced. This can be achieved either by reserving firm, long-term transmission capacity on the NBP transmission system, or by building a new transmission line. The first scenario faces many obstacles and does not necessarily provide customers in northern Maine with access to a competitive wholesale electricity market. Consequently, we believe that the most practical and most effective approach to reducing market power in northern Maine is by building a new transmission line between northern Maine and New England, and having the distribution companies in northern Maine join the New England market by becoming members of the Independent System Operator (ISO-NE).

The other option for reducing NBP’s dominance in the region is to utilize the MEPCO transmission line, in combination with NBP’s Tie Line Interruption Service, to transfer power from New England through New Brunswick to northern Maine. However, this option would not ensure non-discriminatory open access transmission service -- unless NBP was willing to (a) eliminate the discrepancy between its wheel-through and wheel-out transmission prices, and (b) file its transmission tariff at the Federal Energy Regulatory Commission (FERC) for approval.

Recommendations

We recommend that the Commission address the market power issue from a number of angles. The overarching goals of the Commission should be twofold: (1) to encourage the distribution companies within northern Maine to join the competitive wholesale electricity market in New England, and (2) to reduce the influence of NBP over the transmission of power into northern Maine. To help achieve these goals, we recommend the following actions:

1. Conduct further research. There are a number of areas where further research will shed light on some important issues raised in our study. For example, the Commission should:

- Require MPS to conduct a thorough review of the costs and benefits of joining ISO-NE. The review should account for the benefits of reducing market power concerns in northern Maine.
- Review TransEnergy's study of constructing a transmission line from Hydro-Québec to MPS. An initial draft of the study is due to be completed soon.
- Periodically review the developments of the Northern Maine Working Group on Settlement, to determine the extent to which this route will increase competition in the wholesale electricity market in northern Maine.
- Urge MEPCO to study of the economic and business potential of constructing a new transmission line from MEPCO to MPS.

2. Use whatever political leverage is available to encourage NBP to provide truly non-discriminatory, open-access transmission service. One reasonable approach would be to request NBP to file its open-access transmission tariff with FERC. Another is to request NBP to remove the discrepancy between its wheel-through and wheel-out transmission prices.
3. To the extent that the previous option is unsuccessful, the Commission should encourage the investigation of a new transmission line between New England and MPS. The Commission should begin discussions with MPS, CMP, BHE, and MEPCO to investigate the advantages and disadvantages of constructing such a line, as well as who would act as project developer for the line.
4. Encourage the distribution companies in northern Maine to join the ISO-NE. This initiative may depend upon the outcomes of the previous two options.
5. Require MPS to adopt similar market power monitoring and prevention mechanisms as available through the ISO-NE, unless and until the distribution companies in northern Maine join the ISO-NE.

2. Competition in Northern Maine Under Current Conditions

2.1 Generation Capacity in Northern Maine -- Prior to the MPS Divestiture

In 1997 the peak demand in northern Maine was roughly 123 MW -- which is approximately seven percent of the total demand in Maine, and less than one percent of the demand in all of New England. Table 2.1 provides a summary of the 1997 coincident peak demands of the northern Maine utilities. The native load on the MPS system represents roughly 80 percent of total demand in northern Maine. The other customers are served by two municipal utilities: Houlton Water Company (HWC) and Van Buren Power and Light (VBPL), and one electric cooperative: Eastern Maine Electric Coop (EMEC).

Table 2.1 Coincident Peak Demand of Northern Maine Utilities in 1997.

Utility	Source of Generation	Peak Demand (MW)	Percent of Total
MPS	owns power plants	99.7	81%
Houlton Water Co.	purchases	17.3	14%
Van Buren Light & Power	purchases	3.0	2%
Eastern ME Coop	purchases	2.5	2%
Total	----	122.5	100%

Taken from MPS response to PUC Notice of Inquiry, Docket No. 97-586. Eastern Maine Coop also serves a load of approximately 31 MW through power delivered by NBP. This additional load is not connected to the MPS system.

Table 2.2 provides a summary of the power plants located in northern Maine. The Tinker hydro generating station is currently owned by the Maine and New Brunswick Electric Power Limited (M&NB) -- a wholly owned subsidiary of MPS. MPS is entitled to Tinker's energy and capacity, through a power contract with M&NB.[4] MPS is also entitled to the 18.1 MW of capacity of the Wheelabrator-Sherman wood-fired cogeneration facility, through a qualifying facility contract.

In addition, MPS owns two small hydro facilities and some small diesel units. These units generate only a very small portion of MPS's electricity sales.

MPS also owns shares in the Wyman plant (21 MW) and the Maine Yankee plant (43 MW). Both of these plants are located outside of the northern Maine region. The Maine Yankee plant has been permanently closed, and is therefore not available to provide generation to northern Maine. The MPS shares in the Wyman plant are not considered as capacity available to the northern Maine market, because of limitations in transmission capacity. (See Section 2.3.)

The other two sources of generation in northern Maine are wood-fired power plants owned by the Aroostook Valley Electric Coop (AVEC) and Alternative Energy Inc. (AEI). As indicated in Table 2.2, these two companies own roughly 25 percent of the capacity in northern Maine, while MPS owns or is entitled to the remaining 50 percent.

[4] MPS is required to use a portion of the Tinker output to serve the town of Perth Andover.

Table 2.2 Generation Capacity Located in Northern Maine.

Owner	Fuel Type	Capacity (MW)	Percentage of Total
MPS -- Wheelabrator	Wood	18.1	13%
MPS -- Maine & NB Elec. Power	Hydro - Tinker	33.5	25%
MPS	Hydro - Other	2.3	2%
MPS	Diesels	12.3	9%
Aroostook Valley Elec. Coop.	Wood	32.0	24%
Alternative Energy Inc.	Wood	37.0	27%
Total Generation	----	135.2	100%

Source: MPS response to data request 1-AGO-3, Docket No. 97-877, and Econosult 1998. The Tinker facility is located in Canada, just across the Maine border, but its generation is available to customers in northern Maine.

In addition to the resources described above, MPS has signed short-term contracts (1998-2000) with AEI and NB Power to purchase capacity and energy to replace that which was lost due to the Maine Yankee shutdown. The contract with AEI is for 37 MW and 260 GWh. The contract with NB Power is for 15 MW of capacity and the necessary dispatchable energy to meet MPS's remaining requirements (Bustard 1998).

2.2 Results to Date of the MPS Generation Asset Divestiture

In late 1997 MPS solicited bids for purchases of all of its generation assets, in response to the Maine restructuring legislation's mandate to divest all generation by March 2000. MPS received bids in January 1998, and selected the winning bidder in August 1998. MPS's petition for authorization for the sale of its generation assets is now being considered by the Commission in Docket No. 98-584.

MPS has announced that the winning bidder is WPS Power Development, Inc of Green Bay, Wisconsin. WPS has offered to buy all of MPS's generation assets, including all of MNBEP, which owns and operates the Tinker hydro facility.[5] The proposed sale to WPS includes a Buy-Back Agreement, whereby MPS will have the rights to all capacity, energy and ancillary services of the hydro and diesel units, including the Tinker facility. The Buy-Back Agreement will be in effect through February 2000.

MPS did not put its entitlements in the Wheelabrator-Sherman facility out to bid. Instead, MPS has agreed to sell the output from this facility on a short-term basis at annual auction.

In sum, the MPS divestiture may result in a modest increase in the number of generation companies located in northern Maine. AVEC and AEI will continue to each own 24 and 27 percent of the generation in the region, respectively. WPS will own approximately 36 percent, and whoever purchases the Wheelabrator-Sherman entitlements will hold the remaining 13 percent. If either AVEC, AEI or WPS purchases the Wheelabrator-Sherman entitlements, then their shares of capacity will increase accordingly.

[5] The legislation does not require MPS to divest the Tinker facility because it is located outside the US.

2.3 Transmission Capabilities in Northern Maine

In theory, utilities in northern Maine have access to two broad external electricity markets: Canada to the north and New England to the south. However, in practice access to these markets are severely constrained by transmission ties and institutional practices.

A map of northern Maine and regional transmission interconnections is provided in Appendix A. Unlike other regions of Maine, Aroostook county is isolated from the New England transmission system. MPS's only external transmission links are through New Brunswick Power. Hence all purchases and sales to the New England market to the south must go through NBP, and be transmitted through the MEPCO transmission line between NBP and BHE.[6] Similarly, all purchases and sales to the Canadian markets to the north must be made through NBP.

The transmission capacity between MPS and NBP is 200 MW.[7] The flows of power between MPS and NBP are limited by transmission line conductors and tie line transformer ratings (NBP 3/1998). For planning purposes, MPS assumes that the inter-ties are able to carry 90 MW of power on a firm basis (Bustard, Louridas, Brown 1998). However, one of the four transmission lines between the two companies was only out of service between two and four days over the last two years, indicating that MPS frequently has access to more than 90 MW of transmission capacity with NBP (Econosult 1998). Either way, the transmission capacity between NBP and MPS is quite large relative to the 123 MW peak demand in northern Maine in 1997.

However, from an economic perspective the ability to purchase power through the NBP interconnection is limited by NBP's transmission policies and rates. As of January 1998, NBP has offered what it calls an open access transmission tariff. The tariff only offers "wheel-out" and "wheel-through" point-to-point transmission service. Generating companies are not offered transmission services that terminate within NBP's service territory. The wheel-through rate is roughly 34 $/kW-year and the wheel-out rate is approximately 24 $/kW-year.[8] NBP takes transmission services at it's wheel-out rate, which provides it with an economic advantage over generation companies outside of New Brunswick seeking to transmit power into MPS's service territory. Within northern Maine the cost of transmission is even lower, at an average price of roughly $20/kW-year (Bustard, Louridas, Brown 1998).

NBP has stated that its transmission prices will not be increased over time by more than the increase in the consumer price index (NBP 8/1998). However, NBP is not subject to any regulatory body overseeing its transmission pricing and practices, and it has not filed its transmission tariff at FERC. NBP notes that it believes that over time an independent regulatory body will be established to review and approve its transmission tariff and to set guidelines for a code of conduct (NBP 8/1998). However, for the foreseeable future it

[6] The Maine Electric Power Company is jointly owned by MPS, BHE and CMP, and was established primarily to build and operate the MEPCO transmission line.

[7] There are four transmission lines connecting northern Maine with NBP: two 69 kV lines and two 138 kV lines (NBP 3/1998).

[8] Here we assume an exchange rate of 0.65 US$/C$.

appears as though NBP has the flexibility to alter its transmission policies and prices without regulatory oversight or legal recourse. Consequently, generation companies in the region are likely to be discouraged from depending upon NBP transmission services to sell generation services into northern Maine. (This issue is addressed in more detail in Section 5.)

NBP's transmission pricing flexibility also has a chilling effect on transmission options in the region. Increasing the NBP wheel-through transmission price would further limit the ability of new generation companies to reach northern Maine. Reducing the NBP transmission price would reduce the economic benefits to a third party of building a new transmission line to northern Maine.

Electricity customers in northern Maine face an important barrier arising from constraints on the south-to-north flow on the MEPCO transmission line connecting NBP to NEPOOL. The MEPCO line is subject to stability constraints that require that the line maintains a constant flow of power from New Brunswick to NEPOOL.[9] This north-to-south flow is required to ensure that in the event of the loss of the largest source of power in the Maritime Control Area (usually the Point Lepreau plant or the power from the Hydro Québec transmission lines), there will not be unacceptable voltage and power flow levels over the MEPCO line and into Maine (NBP 3/1998). As a result of this restriction, the line cannot be used to deliver any firm power from the south to the north. This constraint on firm power currently limits the ability of competitive generators in New England to market their generation to customers in northern Maine. It is, however, possible to deliver *non-firm* power from south to north along the MEPCO line.

NBP and MPS have recently negotiated an agreement to address this south-to-north transmission constraint. NBP has created a Tie Line Interruption Service, whereby it will provide MPS with back-up power in the event that the non-firm energy purchase across the MEPCO line is interrupted. The NBP agreement with MPS provides for this service to be available to MPS for five years. NBP has stated that it is prepared to enter discussions with other entities to provide them with similar firm back-up service (NBP 8/1998). (This issue is addressed in more detail in Section 6.2)

2.4 Quantitative Indicators of Market Concentration in Northern Maine

Concentration Ratios and the Herfindahl-Hirschman Index.

Given the small number of generation companies currently operating in northern Maine, in conjunction with the limited transmission capability into the northern Maine region, there is an obvious concern that the retail electricity market in the region would not be adequately competitive under current conditions. This concern can be investigated through the application of quantitative indicators of market power.

Market power arises, in part, due to market concentration and market dominance. The two most common measures of market concentration are the "concentration ratio" and the

[9] The line is capable of delivering up to 700 MW of firm power from north to south (Bustard, Louridas, Brown 1998).

Herfindahl-Hirschman Index (HHI). No single metric can capture the complexities of the cost structures and relationships in a real market, but the HHI and concentration ratio are both useful measures that can serve as a starting point in analyses of market power. In its merger guidelines, FERC uses the HHI as screening tool to identify whether market power might be a problem.

Concentration ratios indicate the extent of the market share of the largest firms in a particular market. For example, the three firm concentration ratio (abbreviated as "CR3") for a market with ten firms of equal size would be 30 percent. In the northern Maine electricity market, there currently exists only three generation companies, so the CR3 is 100 percent. Even after the MPS divestiture there will only be four generation companies, and the CR3 will be 87 percent. Such high concentration ratios obviously indicate serious concerns about market power problems.

The HHI is defined as the sum of the squares of individual firm's market shares (expressed as percentages). For example, an industry with ten firms of equal size would have an HHI of 1000. An industry with five firms of equal size would have an HHI of 2000. Department of Justice (DOJ) guidelines for evaluating mergers indicate that at an HHI above 1800 indicates that the market is "highly concentrated" and adverse effects are "presumed." In such concentrated markets, there are significant concerns of market power, although whether and to what extent there is a problem depends upon a variety of other factors, for example, barriers to market entry (DOJ and FTC 1992). These DOJ guidelines have been incorporated into FERC policy on evaluating market power associated with electric utility mergers (FERC 1996).

HHI Calculations for Northern Maine.

Table 2.3 presents a summary of HHI calculations for various scenarios in the northern Maine region. The assumptions used in calculating these HHI results are presented in Appendix B. We look at three factors that could critically affect the degree of market power in the region: (1) the divestiture of MPS's generation assets, (2) access to NBP's transmission lines to import electricity into northern Maine, and (3) a new transmission line serving the northern Maine region.

Table 2.3 HHI Analysis of Various Scenarios Addressing Market Power

Scenario	HHI
Divestiture of MPS's generation assets:	
1. Before MPS divestiture. (Current conditions.)	2,933
2. MPS divestiture: capacity sold to two buyers. (Same as MPS divestiture to WPS.)	2,525
3. MPS divestiture: capacity sold to three buyers.	2,397
Assuming MPS divestiture to WPS, with access to NBP's transmission line:	
4. HQ (or one NE entity) provided firm transmission access through NBP.	1,727
5. Two NE entities provided firm transmission access through NBP.	1,527
6. Three NE entities provided firm transmission access through NBP.	1,460
Assuming MPS divestiture to WPS, with construction of new transmission lines:	
7. HQ (or single NE entity) provided firm transmission access through new line.	2,157
8. Two NE entities provided firm transmission access through new MEPCO line.	1,684
9. Three NE entities provided firm transmission access through new MEPCO line.	1,526
10. HQ and three NE entities provided firm transmission access through two new lines.	1,446

Source: See Table B.1 in Appendix B for assumptions used in each calculation.

The first scenario represents the current conditions in the region, before the divestiture of MPS's generation assets. (This scenario has the same HHI as a scenario where MPS sells all its generation assets and entitlements to a single buyer.) The next two scenarios indicate how the HHI would change as a consequence of selling MPS's generation assets to either two or three different owners. (Scenario 2 has the same HHI as a scenario where MPS sells its generation assets to WPS, and the Wheelabrator-Sherman entitlements are purchased by an independent generation company.) In all three cases the HHIs are above the 1,800 threshold, indicating that the market would be highly concentrated regardless of the outcome of the divestiture.

In these first three scenarios we assume that NBP is the only entity that is able to provide imported power into the northern Maine region. This assumption is consistent with FERC's guidelines for evaluating the market power effects of mergers. In defining the geographic market for a market power analysis, FERC requires that all suppliers included in the analysis must be able to reach the destination market both economically and physically. FERC uses a delivered price test to assess whether a supplier can economically reach a market. In the delivered price test, a supplier is considered to be able to reach a destination market if the price of doing so is no more than five percent above the pre-merger market price. The delivered price test includes the cost of transmission and ancillary services (FERC 1996).

In the absence of a merger, the delivered price test would presumably require that a supplier can reach a destination market at a price no greater than five percent above the market price (or some indication of a reasonably competitive price). Suppliers wishing to transmit power across NBP's service territory are required to pay transmission prices that are roughly 40 percent higher than the price that NBP charges itself, and roughly 60 percent higher than the average price of transmission in northern Maine. These high transmission prices would apparently cause other suppliers to fail the delivered price test, and therefore not be considered able to reliably serve the northern Maine electricity market.

Our Scenarios 4, 5 and 6 present the effects of generation companies from either Québec or New England gaining access to the northern Maine market through firm transmission from NBP. In Scenario 4 we assume that NBP's 90 MW of transmission capacity into northern Maine is divided into two 45 MW firm increments: one for NBP and one for a generation company located in Québec (or New England). In Scenario 5 we assume that NBP continues to reserve 45 MW of transmission capacity for itself, and allocates the remaining 45 MW in two equal shares to two generation companies located in New England.[10] In Scenario 6 we assume that NBP continues to reserve 45 MW of transmission capacity for itself, and allocates the remaining 45 MW in three equal shares to three generation companies located in New England. In all three of these scenarios, the HHI drops to a level that would pass FERC's market power screening analysis, because NBP's market concentration is reduced to a significant degree.

Scenarios 7 through 10 present the effects of building new transmission lines to import additional power into the northern Maine region. Scenario 7 assumes that a transmission line with 100 MW of firm capacity is installed between MPS and Hydro-Québec (or New England), and that only one entity has access to firm capacity on the line. Scenario 8 is also based on a single new transmission line, but assumes that two parties have access to firm capacity on the line. Scenario 9 assumes that three parties have access to a single new transmission line. Finally, Scenario 10 is a combination of Scenarios 7 and 9; where two new 100 MW transmission lines are constructed, and three entities are provided firm access to the line from New England. [11]

These last HHI results indicate that a single new transmission line is not sufficient to reduce the HHIs down to the acceptable 1,800 threshold, unless that line is shared by at least two independent parties. It is interesting to note that, building new transmission lines (Scenarios 7, 8 and 9) does not reduce the HHIs as much as providing firm transmission capacity through existing NBP lines (Scenarios 4, 5 and 6), because they are not as effective in diminishing the large role that NBP can play in the northern Maine market.

Our methodology for accounting for NBP in the HHI analysis might understate its market power role in one very important respect. We use the 90 MW of firm transmission capacity available between MPS and NBP, as opposed to the full 200 MW of transmission capacity available. While it is important to account for only firm transmission capacity, NBP quite frequently has access to much greater than 90 MW of transmission capacity into northern Maine. We have recalculated all of the HHIs for northern Maine assuming 200 MW of transmission capacity between MPS and NBP.

[10] A transmission line from MPS to New England is likely to mitigate market power much more effectively than the same sized line from Hydro-Québec, because New England offers northern Maine a competitive wholesale electricity market as well as a larger number of competitive generation companies. However, in order to adhere to FERC's guidelines on HHI screening, we only account for those generation companies in New England that are able to reserve firm transmission access on the new line.

[11] In Scenarios 7 through 10 we assume that the new transmission lines would have a total thermal capacity of 150 MW, similar to the lines that are analyzed in Sections 5.2 and 6.3 below. However, we assume that only 100 MW of these new lines would be available for firm transmission capacity, due to transmission operating and reliability constraints.

The results are presented in Table B.2 in Appendix B. They indicate that NBP would have unacceptable levels of market concentration in all of the scenarios, except for Scenario 6 where half of NBP's 200 MW of firm transmission capacity is shared between three separate entities in New England.

In sum, our HHI analysis indicates that there will be a high degree of market concentration in northern Maine under most foreseeable scenarios. The most important factor influencing this degree of concentration is the control that NBP has over the imports of generation into the region. We will discuss the implications of these HHI results in Section 7.1.

2.5 Limitations to the Herfindahl-Hirschman Index.

In practice, the potential for market power problems in northern Maine is likely to be even greater than what is indicated by the Herfindahl indices above. Herfindahl indices cannot account for many of the unique operating conditions that might affect the extent of market power in a particular market. FERC uses HHI analysis as a general screening tool to identify potential broad market power concerns, but recognizes that more detailed analyses are necessary to fully understand how market power might be applied in a particular situation (FERC 1996).

There are five reasons why the potential for market power problems in northern Maine is likely to be even greater than what is indicated by the HHI analysis above. First, the HHI analysis is for the entire northern Maine electricity market, as opposed to distinct product markets that might have different market power implications. When assessing the potential for market power in the electricity industry there are a variety of product markets that should be studied. FERC recommends that market power studies assess at least the non-firm energy, the short-term capacity and the long-term capacity markets (FERC 1998). In addition, the market for ancillary services can provide opportunities for generation companies to exploit market power, as has been demonstrated by the recent electricity price spikes in the California market (CAISO 1998).

Second, the HHI analysis does not account for operational constraints on the generation resources available in northern Maine. If any of the generation resources or transmission interconnections are unavailable due to maintenance, forced outages or fueling requirements, then the operators of other resources will have higher degrees of market concentration. This point is particularly important in northern Maine where there are so few generation resources and transmission interconnections.

Third, with so few generation resources available, there is greater potential for generation companies to "game" the electricity market. When a supply curve of generation resources is composed of very few power plants, there will be greater opportunities to raise the bid price for a particular generator above its variable cost, because the cost of the next generator in the market is higher still. Minor variations in the operation or bid price of each plant can have a relatively large impact on the market price for power. This increased opportunity to game an electricity market with few generation resources would not be identified by an HHI analysis.

Fourth, the HHI analysis assumes that each market participant acts independently of all other participants. If two or more participants were to collude in any way, then the effective HHI results would be significantly higher.

Fifth, there currently is not a competitive wholesale electricity market in northern Maine. Nor is there a competitive wholesale electricity market nearby in Québec or New Brunswick. A fully competitive wholesale electricity market would significantly reduce the potential for market power abuse by promoting open access to transmission lines, providing a bidding system that encourages suppliers to bid their variable operating costs, and increasing opportunities for new generation companies to enter the market.

2.6 The Importance of Accessing a Competitive Wholesale Electricity Market

Ever since FERC released its "mega-NOPR" in 1995, and its Order 888 in 1996, FERC has been actively promoting competitive wholesale electricity markets throughout the US. One of the key ingredients to a competitive wholesale electricity market is open access, non-discriminatory transmission service for all generation companies wishing to sell wholesale power. Another key ingredient is an Independent System Operator (ISO) that oversees the operation, planning and construction of transmission lines. A third key ingredient is a bid-based spot market, where all generation suppliers can bid to sell power to a central pool on an hourly basis, and generation units are dispatched according to the lowest bids received.

In every state that we are aware of where retail markets are being opened up to competition, efforts are also being made to ensure a competitive wholesale electricity market. California has already established an ISO, and the California Power Exchange has recently begun operating the electricity spot market in the state. In New England, NEPOOL is being transformed into the ISO-NE. Utilities within the Pennsylvania-New Jersey-Maryland (PJM) power pool have formed an ISO, which will include a bid-based spot market. ISO's are also being established or proposed in New York (NY ISO), in the Midwest (Midwest ISO), in the East-Central region (Alliance ISO), in Texas (ERCOT ISO), in the Southwest (DesertSTAR), in the Northwest (IndeGO), and in NERC reliability regions known as Mid-Continent Area Power Pool (MAPP) and Southwest Power Pool (SPP) (EIA 7/1998).

A competitive wholesale electricity market can significantly reduce the risk of market power problems at both the wholesale and retail level. A competitive spot market provides a number of benefits over the primary alternative: bilateral contracts between each buyer and seller. A spot market provides greater opportunities for new entrants to participate in the market, and to reach a large number of customers easily and quickly. A spot market provides electricity buyers greater opportunities for purchasing the lowest-cost electricity at all times. A spot market also provides real-time, consistent, reliable and transparent information about market prices and conditions, thereby promoting efficient market behavior (EIA 9/1998).

An ISO can provide greater division between the owners of the transmission systems and the owners of generation resources -- thereby reducing the potential to exploit vertical market power. An ISO can also establish reliability requirements that apply equitably to

all generation companies serving the market. Without such reliability requirements, those generation companies holding highly-desirable capacity during peak periods can exploit capacity shortfalls. An ISO can also establish market monitoring and market power mitigation mechanisms, to detect and address any market power problems as they arise.

2.7 Options Available to Reduce Market Power in Northern Maine

By all measures it is clear that there is likely to be substantial market power problems in the northern Maine electricity market -- absent significant changes to the current conditions. In the remainder of this report, we evaluate various options for reducing the market power concerns in northern Maine.

We have structured this report according to four strategies that could provide opportunities for reducing the market power concerns in northern Maine.

- Increase the amount of competition within northern Maine.
- Increase the amount of competitive generation available from New Brunswick.
- Increase the amount of competitive generation available from Québec.
- Increase the amount of competitive generation available from New England.

In order to implement either of these strategies, a number of actions may be necessary. Depending upon the particular strategy, we investigate the following actions:

1. Increase the number of generators located within northern Maine.
2. Make the wholesale market in New Brunswick more competitive.
3. Convince NBP to provide open-access, non-discriminatory firm transmission capacity into northern Maine.
4. Make the wholesale market in Québec more competitive.
5. Build a new transmission line between Hydro-Québec and MPS.
6. Resolve the south-to-north constraint on the MEPCO transmission line.
7. Build a new transmission line between MPS and MEPCO.
8. Encourage distribution companies in northern Maine to become members of the ISO-NE.

3. Increase the Amount of Competition Within Northern Maine.

There are three options for increasing the amount of competitive generation services within northern Maine: (1) build new power plants, (2) increase the number of owners of existing power plants in northern Maine through the divestiture of MPS's assets, and (3) increase the amount of competition at the wholesale level through institutional means such as an ISO. However, as discussed below, these options have some important constraints that are likely to limit their ability to significantly address market power concerns in the region.

The opportunities to build new power plants in northern Maine are limited by the size of the electricity market. With existing generation capacity of 135 MW and import capabilities from NBP of 90 to 200 MW, there is more than sufficient generation capacity to serve the total peak demand of 123 MW. Consequently, there is little economic incentive for generation companies to build new power plants within northern Maine. In addition, any new power plant located in northern Maine would have to pay NBP's high transmission rates in order to export power out of the region. Furthermore, there are few target markets in the interconnected neighboring regions where a generation company might wish to export power to.

The opportunity to increase the number of generation companies located within northern Maine through MPS's asset divestiture may be limited due to the condition and small amount of MPS's generation capacity. The responses to MPS's solicitation indicates that there is significant commercial interest in MPS's Tinker hydro facility, but little interest in the other generation assets. In fact, the winning bidder, WPS, indicated that absent the Tinker facility they would not have bid on any of MPS's assets (Bustard 1998). Therefore, it appears as though it may be difficult for MPS to sell its generation assets to more than one buyer.

As currently proposed, the MPS divestiture would potentially allow two companies to control the generation assets and entitlements currently controlled by MPS. The assets currently owned by MPS would be controlled by WPS, and the entitlements to the Wheelabrator-Sherman contract would be controlled by whoever purchased them in any given year. The Commission may wish to consider precluding generation companies located in northern Maine from purchasing the entitlements to the Wheelabrator-Sherman contract, in order to limit the concentration of generation control in the northern Maine market. However, this measure is unlikely to have a significant impact on the market power concerns in northern Maine, as indicated by the high HHI result in Scenario 3 in Table 2.3.

In fact, the HHI analysis presented in Section 2.3 indicates that the outcome of MPS's generation asset divestiture is unlikely to reduce market power concerns, because most of these concerns arise as a consequence of NBP's control over the transmission lines into the county. In his testimony on behalf of MPS, Dr. Tabors makes a similar point:

> I believe it is important to point out that market concentration in the region is driven by the existence of New Brunswick and Hydro-Québec (and their

transmission/supply positions), rather than by variations in the sale of MPS's assets (Tabors 1998, page 14).

The third option for increasing the degree of competition in northern Maine -- using institutional measures to establish a competitive wholesale market within Aroostook County -- is also limited by the size of the electricity market in the region. A fully competitive wholesale market would require the creation of an ISO and the establishment of a spot-market power pooling system. However, an efficient electricity spot-market requires that there be a sufficient number of buyers and sellers in the market, and that there be a sufficient number of power plants to compete to set the market clearing price. In addition, given the small number of actors in the northern Maine electricity market, it would be difficult to establish an ISO that is truly independent and that meets all of the responsibilities of the larger ISOs that are being established elsewhere in the US.

It is important to note that the electric companies in northern Maine are currently taking steps to increase the competitiveness of the wholesale electricity market in the region. A "Northern Maine Working Group on Settlement" has been created recently to establish a Bulk Power System Administrator (BPSA). The Working Group is composed of representatives of EMEC, MPS, HWC, VBLP and NBP. It is currently envisioned that the BPSA will handle scheduling, financial settlement, and a day-ahead spot market for all wholesale sellers of electricity in northern Maine. The spot market will include ancillary services, and will rely upon a competitive bidding process (MPS 9/1998).

While the BPSA is an important and positive step toward increasing the degree of competition in the wholesale electricity market in northern Maine, it will not provide many of the services and benefits that are provided by full-scale ISOs such as the ISO-NE. The Working Group itself made a point of noting that it is not creating an ISO, but rather a bulk power administrator whose primary responsibilities are to handle financial settlement between companies and to manage the bidding process (MPS 9/1998). As currently envisioned, the BPSA will not have all the features and provide all the functions of typical ISOs. For example, the BPSA might not:

- have a truly independent governance system;
- ensure open, non-discriminatory transmission access;
- maintain control over the operation of transmission facilities;
- ensure the short-term reliability of grid operations;
- identify transmission constraints on the system and takes operational actions to relieve constraints;
- maintain pricing policies that promote the efficient use of, and investment in, generation and transmission;
- establish a market power monitoring system;
- implement market power mitigation measures; and
- establish an alternative dispute resolution process.

In sum, each of the three options for increasing competition within northern Maine suffers from limitations due to the size of the electricity market in the region. It appears that the only practical means of significantly reducing market power in northern Maine is by looking outside of Aroostook County -- by increasing the opportunities for importing power, and by connecting up to a competitive wholesale electricity market that is established in a neighboring region. These options are discussed in the following chapters.

4. Increase the Amount of Competitive Generation Available From New Brunswick.

New Brunswick Power Company currently has roughly 1,100 MW of surplus generation capacity that could be sold to customers in northern Maine. NBP is currently the dominant player in the northern Maine electricity market. In order to increase the amount of *competitive* generation available from the province of New Brunswick, it will be necessary for independent power producers (IPPs) to construct generation facilities within the province.

Until recently, there was little chance of any IPPs building new facilities within New Brunswick. The province is served entirely by NBP, a vertically integrated Crown Corporation. In fact, the Electric Power Act of New Brunswick provides for NBP to be the monopoly supplier of electricity in the province, and prevents NBP from providing open-access network transmission service (NBP 8/1998).

In 1998 the New Brunswick government opened an investigation into the opportunities for restructuring the province's electricity market (NB Restructuring Task Force 1998; NB Department of Natural Resources and Energy 1998). However, the government has taken a cautious approach to date, and is not expected to make any significant changes to the industry for the foreseeable future. NBP currently has a high level of debt (NB Department of Natural Resources and Energy 1998). This provides the New Brunswick government and NBP with a powerful incentive to limit the amount of competition -- both wholesale and retail -- in the province. MPS recently noted that it does not expect the retail market in New Brunswick to be opened up to competition for several years (Bustard, Louridas, Brown 1998).

However, the New Brunswick government and NBP are currently negotiating with private companies to develop two separate IPP projects in the province. Tractabel has proposed a 350 MW gas plant, to be on-line before the end of 2002. Westcoast has proposed two 250 MW gas units; the first is scheduled to be on-line by the fall of 2000. Both of these plants are expected to take advantage of the Maritime and Northeast Natural Gas Pipeline, scheduled to be in-service by November 1999. Both of these plants are also expected to export all of their generation to electricity markets in the US (Bustard, Louridas, Brown 1998).

It is not clear whether either of these new IPP developers are planing to market their power to customers in northern Maine. One of the key factors may be whether NBP is willing to provide them with firm transmission service to reach northern Maine. Nevertheless, these two proposals could offer some new competitive generation services to the region, and offer hope that the New Brunswick government might allow additional such projects in the future. It is also worth noting that IPP projects located within the province of New Brunswick do not have to pay NBP's high wheel-through transmission tariff, they can pay the lower wheel-out tariff. This means that they might have a greater opportunity to serve the northern Maine market than IPP projects located in Québec or New England.

Because of its direct inter-ties with MPS, NBP would seem to provide the best opportunity for the customers in northern Maine to tap into a competitive wholesale electricity market. However, as described above, the New Brunswick government is unlikely to open the electricity up to either retail or wholesale competition. Therefore, even if northern Maine customers can turn to the province of New Brunswick for access to new generation companies, it will still not be able to access a competitive wholesale market -- one of the key ingredients necessary to mitigate market power concerns in northern Maine.

Given the fact that the lack of a competitive wholesale or retail market in New Brunswick is the primary block to increasing the amount of competitive generation available from New Brunswick, there does not appear to be any practical and adequate actions that the Maine Public Service Commission can do to pursue this particular strategy.

Nova Scotia Power Incorporated

It should be noted that Nova Scotia Power Incorporated (NSPI) is another source of generation supply that could, in theory, reach northern Maine. In the past NSPI has not been an active marketer of its electricity. In addition, it does not have a large surplus of generation capacity -- unlike NBP and Hydro-Québec. NSPI's generation capacity is roughly 2213 MW and its demand is roughly 1856 MW (Bustard, Louridas, Brown 1998). This leaves a surplus of only 19 percent, not much more than is necessary for its own reliability needs.

NSPI has recently indicated that it is interested in selling power to US markets, including the market in northern Maine. NSPI is connected to northern Maine through NBP, and there are no other transmission routes between the two regions. Consequently, NSPI must incur the high wheel-through transmission tariff imposed by NBP. This is likely to limit NSPI's interest in selling its power to northern Maine.

It is difficult to estimate at this time how much of a role that NSPI is likely to play in the northern Maine electricity market. It is safe to conclude that its role is likely to be curtailed somewhat by the high NBP transmission tariff.

5. Increase the Amount of Competitive Generation Available From Québec.

5.1 Access Hydro-Québec Through New Brunswick Power.

In theory, Hydro-Québec could represent an important source of competitive generation for customers in northern Maine. It has roughly 4,500 MW of surplus capacity, it offers low-cost energy from its hydro facilities, and it has expressed a great deal of interest in recent years in selling power to US markets.

However, Hydro-Québec may be precluded from serving the northern Maine market because of the transmission pricing practices of NBP. In its response to the Commission's NOI in this docket, Hydro-Québec states that it is precluded from scheduling transmission through NBP because the NBP tariff is not comparable with Hydro-Québec's tariff. Hydro-Québec has filed an open-access transmission tariff with FERC that requires that all intervening transmission systems offer a service that is comparable with Hydro-Québec's. Hydro-Québec notes the following reasons why its transmission tariff is not comparable with NBP's:

- NBP's transmission tariff does not permit wheel-in transmission service;
- NBP's transmission tariff is discriminatory in that a different set of rates apply to wheel-out and wheel-in services;
- no regulatory body has jurisdiction over NBP's tariff, and thus it can be modified unilaterally at NBP's discretion; and
- NBP has not developed a code of conduct to govern the relationship between its transmission and its merchant functions (HQ 3/1998).

In personal communications with the company, Hydro-Québec has indicated that it has a commercial interest in serving electricity customers in northern Maine. However, they are not making any reservations on the NBP transmission system because of the comparability problem. Customers located in northern Maine seeking to purchase power from Hydro-Québec will have to schedule transmission services through NBP and arrange to pick up the power at the border between Hydro-Québec and NBP (HQ 8/1998).

NBP does not agree with Hydro-Québec about the tariff comparability issue. It believes that Hydro-Québec is able to wheel power through NBP without violating the terms of its tariff. NBP refers to one example of an entity that is under FERC jurisdiction and has used NBP's tariff to wheel electricity from Hydro-Québec through NBP. NPB also points out that an independent generation company within the province of Québec is fully able to wheel power through NBP's transmission system (NBP 8/1998).

MPS also does not agree with Hydro-Québec about the tariff comparability issue. MPS believes that Hydro-Québec is using the comparability issue to prevent NBP from selling power into Québec, because Hydro-Québec cannot sell power into NBP's service territory (since NBP does not have a wheel-in tariff). MPS also points out that HQ is using the

NBP transmission system to wheel power (both sales and purchases) to third parties outside of New Brunswick (MPS 8/1998).

Hydro-Québec disagrees with NBP's and MPS's interpretation of the comparability issue. Hydro-Québec points out that there are a few examples of Hydro-Québec purchases and sales that require wheeling power through NBP. However, in these cases the power marketers have chosen the delivery point to be at the HQ/NBP border, and have reserved the transmission capacity through NBP. In these instances Hydro-Québec is not violating the reciprocity clause of its transmission tariff, because it does not utilize the NBP transmission tariff -- it is essentially just selling the electricity at its border. In addition, Hydro-Québec is not using the power marketer to do indirectly what it is precluded from doing directly -- i.e., selling its own power into the service territory of an entity with non-comparable transmission tariffs (HQ 8/1998).

A brief review of the reciprocity clauses of the two companies' transmission tariffs does not resolve the issue. While it is clear that Hydro-Québec has the option of prohibiting NBP from using the Hydro-Québec transmission system on comparability grounds, it is not entirely clear that Hydro-Québec is precluded from using NBP's transmission system if it wishes to do so.[12]

Nonetheless, NBP's reluctance to provide open-access, non-discriminatory transmission service is likely to create a significant deterrent to Hydro-Québec's interest in selling power over NBP's lines. In addition, Hydro-Québec has little incentive to sell power over NBP's transmission lines at the high wheel-through rate when it can instead sell power to other parts of New England at more reasonable transmission rates.

Regardless of whether Hydro-Québec is literally precluded from transmitting power across NBP's lines, or whether it does not wish to because of the dominant role played by NBP, the fact is that Hydro-Québec has been very clear that it does not intend to market power into northern Maine through the NBP system. Therefore, it would not make sense to rely upon Hydro-Québec selling power through NBP as an option for resolving market power concerns in northern Maine

In theory, private generation companies located in Québec could sell power to customers in northern Maine through Hydro-Québec and NBP. However, we are not aware of any private IPP projects being developed in Québec in the foreseeable future. Furthermore, any such generation company would face the high transmission tariff of NBP, and would probably prefer to sell its power to the larger market in New England to the south.

5.2 Build a New Transmission Line From Hydro Quebec to Northern Maine.

Exponent and Synapse have spoken with representatives of HQ, MPS, and HWC to determine the feasibility and potential constraints of a new transmission line from Hydro-

[12] It appears as though it is the NBP tariff, not the HQ tariff, that might prevent NBP from allowing HQ to use the NBP transmission lines. The NBP tariff requires that any transmission customer provide comparable transmission services to NBP's. HQ's transmission tariff is not comparable to NBP's -- it is better (i.e., non-discriminatory). Does this mean that HQ should be precluded from using NBP's tariff? NBP does not think so, and is not subject to any regulatory body that could require this.

Québec to northern Maine. This line would bypass NBP, therefore any power transfers over the line would not be subject to NBP transmission tariffs.

Based on discussions with HQ, MPS and HWC, there are two options to transfer power directly from HQ to Northern Maine: (1) construct an AC transmission line through a back-to-back HVDC converter from HQ to MPS; (2) construct a radial transmission line from HQ to serve isolated loads ("block loads") in Northern Maine (HQ presently supplies block loads to Citizen's Energy in Vermont). The first option is reviewed here.

Technical constraints require a back-to-back HVDC converter for an AC interconnection between HQ and the existing power grid in Northern Maine. As such, the most feasible interconnection point for the new line from the HQ system is at the existing Madawaska back-to-back HVDC converter. Connecting on the East Side of this converter would avoid the prohibitive cost of a new back-to-back converter. The existing converter at Madawaska is owned entirely by HQ and located within the Province of Quebec. Also, based on discussions with HWC, prior contractual obligations between HQ and NB for the use of this converter are no longer in force.

Based on discussions with MPS representatives, the most feasible interconnection point for a new line to Northern Maine is at Flo's Inn substation in the MPS system. Flo's Inn is a relatively strong substation with nearby voltage support at Tinker and Beechwood substations.

A new transmission line from Madawaska to Flo's Inn would proceed southwesterly from Madawaska along the Quebec/New Brunswick border for approximately 25 miles to the Quebec/Maine border, and then proceed southeasterly for approximately 75 miles to Flo's Inn. The total length of the new line would be approximately 100 miles.

The maximum practical loading of a typical 100-mile 138-kV transmission line is approximately 150 MVA, based on conductor thermal limits and stability considerations. Such a line could be designed and constructed for peak ratings of 150 MVA. Technical studies (power flow, short circuit and stability) would be required to determine any necessary reinforcements at Flo's Inn. Otherwise, no operational or physical constraints for this new line have been identified.

The estimated cost of a new 100-mile, 138-kV line is $35.6 million, based on $356,000 per mile (see Table A.1 in Appendix A). In addition, estimated substation costs are $3.6 million at Madawaska (including a 150-MVA transformer, three 345-kV and one 138-kV circuit breakers) and $0.5 million at Flo's Inn (including two 138-kV circuit breakers). The total estimated cost of the 100-mile line and substations is $39.7 million. This cost estimate does not include costs for right-of-way purchase or costs of any reinforcements at Flo's Inn, if necessary.[13]

The total $39.7 million cost for this transmission line translates into an annual capacity cost of roughly 32 to 48 $/kW-year.[14] This is equivalent to an energy cost of roughly

[13] The estimated cost of a 150-MVA back-to-back HVDC converter is far in excess of $100 million.

[14] Here we assume a fixed charge factor of 12 percent. The low end of the range is based on the full 150 MW thermal capacity of the line. The high end of the range is based on the assumption that only 100 MW of firm capacity will be available due to reliability and stability constraints.

0.58 to 0.87 c/kWh.[15] This estimate should be seen as a very rough illustration of the magnitude of the likely cost of such a transmission line.

In order to determine whether this transmission line is cost-effective, it should first be compared to the cost to Hydro-Québec of transmitting power through NBP. NBP currently charges roughly 34 $/kW-year to transmit power across its lines, which suggests that the new line is not necessarily a more cost-effective option for serving the electricity market in northern Maine -- depending upon how much it could be relied upon for firm transmission capacity.

In addition, NBP's ability to alter its transmission rates poses some uncertainty to the economics of a line from HQ to northern Maine. If NBP were to significantly lower its wheel-through transmission rate, then the HQ-MPS line would be less economic -- partly because Hydro-Québec would have a less expensive option, and partly because the lower NBP transmission rate might bring a greater number of competitors into the northern Maine market. In its testimony seeking authorization for sale of its generation assets, MPS describes the ability that NBP has to competitively price its transmission services in this way, and therefore to influence the interest and ability of other entities to build new transmission lines into northern Maine (Bustard, Louridas, Brown 1998).

Furthermore, in order for this new transmission line to be in Hydro-Québec's economic interest, the cost of the line would have to be recovered from the revenues that Hydro-Québec can make on the sales to the northern Maine electricity market. Given the small size of the market in northern Maine, it is not at all certain that Hydro-Québec would be able to make enough sales to that region sufficient to recover the costs of this transmission line.

It is important to note that Hydro-Québec's energy marketing subsidiary, TransEnergy US, is interested in serving the northern Maine electricity market. They are currently investigating the cost of constructing a transmission line from HQ to northern Maine. They expect to have a preliminary cost estimate for such a line by the end of September 1998. While they could not provide any early results as of the date of this study, they did indicate that they are investigating newer technologies that might cost less than those we used in our estimates above (TransEnergy US 8/1998). Once they have prepared a cost estimate, they will then investigate whether the market in northern Maine is desirable enough to warrant the cost of building the new transmission line.

[15] Here we assume a load factor of 60 percent and total losses of 11 percent.

6. Increase the Amount of Competitive Generation Available From New England.

6.1 Access New England Through New Brunswick Power.

New England offers the greatest opportunity to increase the number of competitive generators serving northern Maine.[16] All of the New England states are opening up their retail electricity markets to competition. Power developers have recently requested interconnection studies to build a total of nearly 30,000 MW of new capacity in New England to serve the evolving competitive market (ISO-NE 6/1998).[17] NEPOOL is being transformed into ISO-NE, which should significantly increase the degree of wholesale electricity competition in the region. In fact, New England offers northern Maine the only practical opportunity for tapping into a competitive wholesale electricity market.

NBP is currently connected to New England through the MEPCO transmission line. In addition, BHE is planning to build a new transmission line that would connect it with NBP. BHE expects that the line would have roughly 300 MW of firm transmission capacity. Bangor Hydro is building the line for the purpose of selling firm transmission service on the line. In fact, it may wait to obtain an interested purchaser of the line before constructing it (BHE 9/1998).

Any generation company from New England wishing to serve northern Maine would have to transmit its power across NBP and would thus have to pay NBP's high wheel-through transmission rate. This high rate clearly creates a barrier for generation companies in New England trying to reach northern Maine.

In addition, it is likely that generation companies in New England will be hesitant to market power to northern Maine because of the influential role that NBP plays in the transmission of power and the lack of regulatory oversight over NBP's transmission services. Generation companies are likely to be concerned that NBP can unilaterally adjust transmission rates and can discriminate against certain generation companies. Even if NBP does not display a tendency to adjust rates or discriminate against any companies, the risk that it could do so may be enough to deter many generation companies. Consequently, this option by itself cannot be counted on to provide much of a solution to the market power concerns in northern Maine.

Furthermore, the ability of any New England generation company to serve customers in northern Maine could be significantly hampered by the limitations on the south-to-north flow on the MEPCO line. This issue is discussed in more detail in the following section.

[16] Although northern Maine is part of New England, we use the term "New England" here to refer to the electricity market within the existing NEPOOL grid.

[17] These are requests for interconnection studies only; it is unlikely that all of this generation capacity will be constructed.

6.2 Improve the South-to-North Flow on the MEPCO Transmission Line

As described in Section 2.3, the existing MEPCO transmission line is not capable of carrying any firm capacity from the south to the north, as a result of stability and reliability constraints. However, NBP has recently established a Tie Line Interruption Service, whereby it will provide generation companies with back-up power in the event that the non-firm energy purchase from the south across the MEPCO line is interrupted.

NBP recently signed a five-year contract with MPS to provide the Tie Line Interruption Service, and has indicated that this same service will be made available to any other entity. There are no reservation fees or capacity fees required for the service; it would be a pay-as-you-go service. The back-up service would be available at an energy-only price that reflects the costs to NBP plus 20 percent (NBP 8/1998). NBP believes that it currently has sufficient capacity to provide this service without building any new power plants. It also expects that the backup service will likely be very rarely needed, because it would only be required under conditions of an unexpected loss a major power source in the region (ME AG 9/1998).

The NBP Tie Line Interruption Service could provide an important opportunity for generation companies in New England to reach the northern Maine electricity market, and to tap into the ISO-NE spot market for power. The establishment of this service means that the MEPCO transmission line is likely to be the most immediate and practical option available for increasing the amount of competition in the northern Maine electricity market.

However, the extent of this opportunity will depend upon the degree to which NBP is committed to provide transmission service to all interested generation companies on a non-discriminatory basis. Since the MEPCO line does not currently connect to northern Maine directly, transactions with New England generation companies or with the ISO-NE will still have to pass through New Brunswick and pay the higher NBP wheel-through transmission tariff. In order for generation companies in New England to receive non-discriminatory open access transmission services to northern Maine through the MEPCO line, NBP would have to provide such transmission services through its own system. To date, NBP has not demonstrated a willingness to do so.

In order for policy-makers in Maine to be assured that NBP will provide open access, non-discriminatory transmission access through the MEPCO line, NBP should take two important steps. First, it should eliminate the difference between its wheel-through and wheel-out transmission tariffs. Second, it should file its transmission tariff at FERC for approval as an open access non-discriminatory transmission tariff. If NBP does not take these two steps then generation companies will be wary about relying upon NBP to reach northern Maine, and regulators should be circumspect about the extent to which this option can resolve market power problems.

The proposed transmission line between BHE and NBP might also help mitigate the south-to-north transmission constraint on the MEPCO line, by providing another route for power exchanges between New England and New Brunswick. Similarly, the tap into the MEPCO transmission line proposed by Bowater paper company (see below) might help to mitigate these constraints. However, it is not possible to quantify the extent to which

these new transmission projects would mitigate the constraint without conducting power flow studies.

6.3 Build a New Transmission Line from NEPOOL to Northern Maine.

Estimated Cost of a New Transmission Line

The most likely opportunity for a transmission line to link northern Maine with the rest of New England would be to run a new line between MPS and the existing MEPCO transmission line. In 1984, Power Technologies Inc. (PTI) conducted a load-flow study of such a line (PTI 1984). We utilize the results of the PTI study to estimate the appropriate configuration of a tap into the MEPCO transmission line. We then use a more recent study to estimate the cost of that particular configuration (Acres 1996).

The existing MEPCO line is 345 kV and runs from Keswick, New Brunswick to Orrington, Maine. The PTI study investigated an interconnection between MPS's 69-kV Mullen substation and a new substation at Haynesville on the MEPCO line. Figure 1 in Appendix C shows a single-line diagram of this proposed interconnection, which consists of the following facilities:

(1) An extension to Mullen substation containing:

- One 138-kV and one 69-kV circuit breaker
- One 69/138-kV transformer

(2) A 138-kV Mullen-Haynesville transmission line of about 25 miles

(3) A substation at Haynesville containing:

- A 345-kV bus
- Three 345-kV and one 138-kV circuit breakers
- A 138/345-kV transformer

The PTI study showed a peak flow of 37 MVA (36.6 MW and 1.1 Mvars) on the proposed Mullen-Haynesville interconnection under one set of 1985 peak load conditions with 56.5 MW of cogeneration added to the MPS system. The study also showed a peak flow of 49 MVA (48.7 MW and 1.9 Mvars) under another set of 1985 load conditions with 56.5 MW of cogeneration added.

Based on a peak flow of 50 MVA in the year 2000 and an average annual increase of 3% over a thirty-five-year expected transmission-line life, normal peak flow in the year 2035 would be approximately 150 MVA on the proposed interconnection.

MPS's response to the Commission's NOI in this docket includes system one-line diagrams proposing two alternatives for the interconnection (MPS 3/1998). MPS's alternative II proposes a 25-mile 138-kV line from Mullen to Haynesville, a 150-MVA autotransformer at Haynesville, a 50-MVA autotransformer at Mullen, and associated substation equipment. The normal peak flow for this alternative would be limited to 50 MVA by the Mullen autotransformer.

MPS's Alternative I proposes a rebuild of 41-mile Line 6910, upgrading from 69kV to 138kV, in addition to the equipment proposed in Alternative II. Line 6910 is one of two existing 69-kV lines from Mullen to Flo's Inn. During telephone discussions with MPS, it indicated that a normal peak flow of 150 MVA on the proposed interconnection would require the rebuild on Line 6910 in order to increase the transfer capability between Mullen and Flo's Inn. It is noted that the 1984 PTI study did not consider flows above 50 MVA on the proposed interconnection.

Cost estimates in this report are provided in two stages for the proposed Haynesville-Mullen interconnection. Stage 1, which is adequate for 50 MVA normal peak flow on the interconnection, is the MPS Alternative II. Stage 2, which increases the normal peak capability to 150 MVA, is the rebuild of Line 6910, MPS's Alternative I.

Figure 2 in Appendix C shows the transmission line configuration selected for the cost estimate: a 138-kV shielded single-circuit line, H-frame wood-pole construction.

Alternative configurations for 138-kV overhead lines include the following: wood-pole H-frame; wood-pole H-frame with compact phase spacing; wood-pole with compact delta arrangement; steel pole with vertical arrangement; steel pole with compact vertical arrangement; steel pole with delta arrangement; and steel pole with compact delta arrangement. In 1996, Acres International investigated the costs of these configurations for 115-kV transmission in Connecticut (Acres 1996). Acres reported the wood-pole H-frame configuration to have the lowest cost. Other recent studies have shown that, for most overhead line applications, treated wood remains the most cost-effective material in terms of both initial and total life-cycle costs, when compared to steel, fiberglass, or concrete (Electrical World 1997).

Table 6.1 gives the construction cost estimate for the proposed Haynesville-Mullen interconnection. The construction cost estimate is $13.6 million for Stage 1, and $15.5 million for Stage 2, leading to a total cost of $29.1 million. The total $29.1 million cost for this transmission line translates into an annual capacity cost of roughly 23 to 35 $/kW-year, depending upon how much firm transmission capacity is available after accounting for reliability and stability concerns.[18] This is equivalent to an energy cost of roughly 0.44 to 0.66 c/kWh.[19]

[18] Here we assume a fixed charge factor of 12 percent. The low end of the range is based on the full 150 MW thermal capacity of the line. The high end of the range is based on the assumption that only 100 MW of firm capacity will be available due to reliability and stability constraints.

[19] Here we assume a load factor of 60 percent and total losses of 3.5 percent.

Table 6.1 Construction Cost Estimate – Proposed Haynesville-Mullen Interconnection

Stage 1	Cost
Extension to the Mullen Substation	$1,030,000.
25-mile 138-kV line ($356K/mile)	$8,936,780.
Haynesville Substation	$3,550,000.
Regulatory Cost	$118,000.
Subtotal – Stage 1	$13,634,780.
Stage 2 (rebuild of Line 6910)	
42-mile 138-kV line ($356K/mile)	$14,669,136.
Mullen termination	$365,000.
Flo's Inn termination	$430,000.
Regulatory Cost & Permit Fees	$50,000.
Subtotal – Stage 2	$15,514,136.
TOTAL	$29,148,916.

Source: See Appendix C.

More details on these construction cost estimates are provided in Appendix C. Table C.2 gives the construction cost estimate per mile for the proposed 138-kV line. This estimate is based on the estimate given in the Acres report for a 115-kV single-circuit, overhead, H-frame, wood-pole transmission line (Acres 1996). Cost estimates in the Acres report have been updated in Table C.2 for 138-kV construction. As shown, the cost is $356,047 per mile, excluding the cost for purchasing right-of-way. Table C.3 gives construction cost estimates for the substations at Haynesville, Mullen, and Flo's Inn. Sample material costs are given in Table C.4.

Similar Tap Line Proposed by Bowater Paper Company

The Bowater paper company (formerly Great Northern Paper) has proposed the construction of an 11.7-mile, 115-kV, 225 MVA, transmission line from its mill in East Millinocket to a new substation and tap on the MEPCO line at Mattaseunk (north of Chester). The estimated cost of this tap line, provided by Duke Engineering & Services, is $250,000 per mile, which is based on single wood-pole construction with the three phases in a delta configuration on post insulators. For our cost estimate of the 138-kV line in Table 6.1, we assume an H-frame wood-pole construction, with a cost of $356,000 per mile. We choose this configuration because it is consistent with standard construction in New England and its superior performance under storm loading (wind and ice, as well as lightning).

Following a modernization program, Bowater's peak load is estimated at 195 MW. Bowater proposes to purchase an average of 71 MW via its proposed tap line, with the remaining load served by Bowater generation. It is expected that the south-to-north transfer capacity over the MEPCO line would be increased by the improved voltage support that the proposed Bowater tap line provides. However, power-flow studies are required to determine the increase in transfer capacity.

The New Line Might Not Resolve the South-to-North Transmission Constraint.

MPS claims that if the new line were connected at Haynesville, existing south-to-north transfer limitations would not be improved (MPS 3/1998). In particular, following a disturbance resulting in the loss of the largest single generating unit, the new Mullen-to-Haynesville line would likely trip out of service. In the opinion of HWC, south-to-north transfer limitations would be improved if the new line were connected at Orrington, rather than Haynesville (HWC 6/1998). However, the length of a new line from Mullen to Orrington would be greater than 50 miles. Operational studies (power flow and stability) would be required to examine these operational issues further.

Therefore, all of the issues discussed in Section 6.2 would continue to pertain to this new transmission line. Anyone wishing to obtain firm capacity on the new line would have to arrange for NBP's Tie Line Interruption Service. While this service might resolve the south-to-north constraint on the new line, it would be at a heavy price. Not only would customers have to pay a 20 percent mark-up on the costs of back-up power, they would also be subject to NBP's discretion about when the back-up power would be made available. More importantly, reliance upon the NBP Tie Line Interruption Service means that the new MEPCO tap line -- which was intended to bypass the NBP transmission system and dominant role in the region -- would be subject to some degree of NBP intervention after all.

Technical Concerns With the New MEPCO Tap Line.

The PTI study identified two potential problems with this new line. One is the possibility of a large power flow through the MPS system should the Keswick end of the 345-kV MEPCO line inadvertently open while both the Orrington end and the tap at Haynesville remain closed. The other is the likelihood of high voltages in the southern part of the MPS system should the Keswick and Orrington ends of the MEPCO line be opened before the tap at Haynesville is opened. The PTI study concluded that special steps in the design of the protection and control of the 345-kV MEPCO line are warranted to overcome these problems.

MPS also raises reliability and safety issues associated with the new MEPCO tap line. It notes that the line could cause MPS's entire system to become radial and would require at least two of the three interconnections with NBP to be closed (MPS 3/1998). However, MPS also notes that while these issues are of "paramount concern" for the company, it could utilize some form of relay protection in order to maintain its connections with NBP and avoid making its entire system radial. MPS does not expect that this protection would require any substantial expense that would undermine the potential for building the new MEPCO transmission tap (MPS 8/1998).

Construction and Payment of the New Line.

MPS and MEPCO are the two likely developers of a new MEPCO tap line. MEPCO would be acting on behalf of its member companies (BHE, CMP and MPS).

MPS has not expressed an interest in constructing the MEPCO tap line. It does cite the line as the most commonly analyzed route for bringing power into northern Maine from

New England, but it also raises a number of reliability and stability concerns about such a line (Bustard, Louridas, Brown 1998; MPS 3/1998).

A CMP representative has expressed some interest in the potential business opportunities of the MEPCO tap line. CMP could build the line through their affiliation with MEPCO, and could use it to sell transmission capacity to generation companies seeking to transmit power into or out of northern Maine. However, CMP has not studied this issue in depth, and does not currently have any plans to do so (CMP 1998).

BHE has no economic or business interest in the tap from the MEPCO line to northern Maine, according to a company representative (BHE 9/1998). However, this does not necessarily mean that they would be opposed to MEPCO participating in the construction of such a line.

It appears as though the line would have to be paid for by either MPS or MEPCO, depending upon who is the primary developer of the line. The costs of the new transmission line would then be rolled into the existing transmission rates of the project developer.

ISO-NE is currently developing protocols for paying for the construction of new transmission lines that serve NEPOOL grid. For new transmission lines constructed for the purpose of connecting a new power plant to the grid, ISO-NE has proposed that the costs of the transmission line be shared equally between the power plant developer and ISO-NE transmission owners (up to a certain cap). For new transmission lines constructed for the purpose of connecting ISO-NE with a neighboring system, ISO-NE has proposed that the cost of the transmission line be paid by the transmission line developer, but that any costs incurred to modify or upgrade the existing NEPOOL transmission system would be shared equally by ISO-NE and the transmission line developer (CMP 1998).

The MEPCO tap line would likely be considered as a new transmission line constructed for the purpose of connecting ISO-NE with a neighboring system. If so, then a portion of the costs on the New England side of the line might be paid by ISO-NE. However, this is not a certainty. If the MEPCO tap line were to be developed by MPS, then ISO-NE might be hesitant to share in any of the costs, on the grounds that the line was primarily being built for the benefit of the neighboring system (CMP 1998). The transmission utilities in ISO-NE are likely to be hesitant to share a portion of the cost of the MEPCO line, because that would cause their own transmission rates to increase slightly.

In sum, it appears as though the majority, if not the entirety, of the costs of the new MEPCO transmission line would have to be borne by the project developer, which is likely to be either MPS or MEPCO.

6.4 Encourage the Northern Maine Distribution Companies to Join ISO-NE.

A new transmission line from MPS to MEPCO would allow more generation companies to serve electricity customers in northern Maine, through bilateral contracts. Such a line would increase the degree of competition in northern Maine at both the retail and wholesale level.

However, in order to enjoy all of the benefits available from the competitive wholesale generation market in New England, MPS, HWC, VBLP and EMEC would have to join the ISO-NE. Joining the ISO-NE would create the following benefits for the electricity market in northern Maine:

- Retail and wholesale electricity customers in northern Maine would have access to the wholesale spot market in New England, providing an important alternative to the generation companies in the northern Maine.
- As described in Section 2.6, a spot market provides greater opportunities for new entrants, increases the ability of purchasers to obtain the lowest-cost electricity, and promotes more efficient market behavior by providing consistent, reliable and transparent information on a real-time basis.
- Generation companies located in northern Maine would have access to the wholesale spot market in New England. This access would provide important opportunities to sell outside of northern Maine, and it would provide opportunities to purchase power from the pool to complement or back-up the power sales within northern Maine.
- Generation companies seeking to sell Standard Offer services in northern Maine would have access to the wholesale spot market in New England.
- Load serving entities in northern Maine would be required to adhere to the ISO-NE reliability requirements, thereby improving the reliability of power supplies in the northern Maine region.
- The Commission and the distribution companies in northern Maine would be able to take advantage of the market power mitigation measures that are currently being established by ISO-NE. These measures would provide (a) a mechanism for identifying and resolving market power problems as they arise in northern Maine, (b) lessons and insights from the identification and resolution of market power problems in New England, and (c) a benchmark for assessing the severity and frequency of market power problems that arise in northern Maine.

There will be some costs associated with joining the ISO-NE. In addition to the $500 annual membership fee, members are allocated indirect costs associated with the ISO operation, including regional network service costs, congestion costs, and ISO operating expenses (ISO-NE 10/1998, CMP 1998). The transaction-based costs are allocated on the basis of load, so the costs for the Maine transmission and distribution utilities will be relatively small.

It is possible for MPS, HWC, VBLP and EMEC to become members of the ISO-NE without becoming members of NEPOOL.[20] If these utilities join the ISO-NE, there does not appear to be many additional benefits available from joining NEPOOL as well. The only obvious benefit is that by being a member of NEPOOL these utilities would be able to play a role in the ISO decision-making process, allowing them to influence policies

[20] Load serving entities that own generation must be a member of NEPOOL in order to be a member ISO-NE. After the MPS divestiture, none of these utilities will own generation capacity.

regarding transmission pricing, planning and siting, spot market operation and protocols, and reliability requirements. However, their representation in the ISO-NE is likely to be very small given the size of their loads.

In the past, the Commission required MPS to conduct periodically a study of the costs and benefits of becoming members of NEPOOL. These NEPOOL Entry Studies found that the costs to MPS of joining NEPOOL were greater than the benefits to MPS. The most recent NEPOOL Entry Study was filed with the Commission in December 1992, and found that the costs of joining NEPOOL exceeded the benefits by roughly $0.9 to $1.3 million per year. The study looked at the costs and benefits associated with three aspects of joining NEPOOL: operation and dispatch, transmission and wheeling, and administration expenses such as billing and management. The study found that costs exceeded benefits in each of these three areas.

MPS has not conducted a study of the costs and benefits of joining ISO-NE. Through personal communications with company representatives, MPS noted that it would be difficult to perform an updated NEPOOL Entry Study at this time because of all the uncertainties and unresolved issues associated with the transition from NEPOOL to ISO-NE.

We believe that this is an opportune moment for conducting a study of the costs and benefits of MPS (as well as HWC, VBPL and EMEC) joining ISO-NE. The results of earlier NEPOOL Entry Studies are no longer relevant. The three aspects studied by MPS in the past -- dispatch, transmission and administration -- will be fundamentally different under the ISO-NE, and could easily have benefits that exceed costs. A study of joining ISO-NE should investigate the following issues:

- What are the costs, benefits and implications of northern Maine utilities becoming members of ISO-NE? What are the benefits to northern Maine in terms of reducing market power concerns?
- What are the costs, benefits and implications of northern Maine utilities becoming members of NEPOOL?
- To what extent could the existing MEPCO line be used by utilities in northern Maine to access the ISO-NE?
- What are the costs, benefits, and implications of building a new transmission link between MPS and NEPOOL, in order for northern Maine utilities to become members of ISO-NE?

New England offers electricity customers in northern Maine the only opportunity to access a competitive wholesale electricity market in the foreseeable future. Therefore, we believe that a study of the costs and benefits of joining ISO-NE should be one of the highest priorities of the Commission in its efforts to address market power issues in Maine.

7. Conclusions and Recommendations

7.1 Synthesis of Our Analysis

It is clear that under current conditions the electricity market in northern Maine is likely to be subject to market power problems. The primary causes of market power in the region are: the isolation of the market, the small size of the market, the lack of access to a competitive wholesale electricity market, and the dominant role played by NBP in the region.

While many of these causes can be addressed by the strategies and options discussed in the study, the greatest cause of market power concern -- New Brunswick Power -- poses a significant challenge. NBP has the ability to exploit its role as the only provider of transmission into northern Maine, thereby limiting the amount of competitive generation suppliers that can reach the area. Not only does it have control over the current transmission into northern Maine, it could also play an influential role in many of the solutions that we have considered in this study:

- Hydro-Québec is not able, or willing, to sell power into the northern Maine market, due to the high NBP wheel-through tariff.
- NBP could reduce the economic benefits of building a new transmission line from Hydro-Québec to MPS, by reducing the price of its wheel-through tariff.
- Generation companies in New England are reluctant to sell power into the northern Maine market, due to the high NBP wheel-through tariff.
- Those generation companies that choose to sell power into the northern Maine market over the existing MEPCO line would have to buy back-up Tie Line Interruption Service from NBP.
- NBP could reduce the economic benefits of building a new transmission line from New England to MPS, by reducing the price of its wheel-through tariff.
- Those generation companies that wish to sell power into the northern Maine market over a new MEPCO tap line would have to buy back-up Tie Line Interruption Service from NBP.
- The only option that we have considered in this report that does not require some role by NBP is that of increasing the number of competitive generation companies within northern Maine. However, the opportunities here are quite limited, as discussed in Section 3, and our HHI analysis indicates that this option will not significantly reduce the market power problem.

Another important conclusion of our analysis is that accessing a competitive wholesale electricity market would provide significant benefits to customers in northern Maine, and should be a priority option for addressing the market power concerns in the region. The only practical option for accessing a competitive wholesale electricity market within the foreseeable future is by joining ISO-NE. Therefore, the Commission should place a

priority on investigating options that allow distribution companies in northern Maine to join ISO-NE.

It is useful to review our HHI analysis presented in Section 2.4. The results are presented again in Table 7.1 for convenience. The HHI analysis, combined with our conclusions above, indicates that there is only one practical approach available to reduce market concentration in northern Maine down to acceptable levels in the near- to mid-term future. That approach would include the construction of a new transmission line between New England and MPS, and the allocation of firm rights to that line among at least two different parties (i.e., our Scenarios 8 and 9).

Table 7.1 HHI Analysis of Various Scenarios Addressing Market Power

Scenario	HHI
Divestiture of MPS's generation assets:	
1. Before MPS divestiture. (Current conditions.)	2,933
2. MPS divestiture: capacity sold to two buyers. (Same as MPS divestiture to WPS.)	2,525
3. MPS divestiture: capacity sold to three buyers.	2,397
Assuming MPS divestiture to WPS, with access to NBP's transmission line:	
4. HQ (or one NE entity) provided firm transmission access through NBP.	1,727
5. Two NE entities provided firm transmission access through NBP.	1,527
6. Three NE entities provided firm transmission access through NBP.	1,460
Assuming MPS divestiture to WPS, with construction of new transmission lines:	
7. HQ (or single NE entity) provided firm transmission access through new line.	2,157
8. Two NE entities provided firm transmission access through new MEPCO line.	1,684
9. Three NE entities provided firm transmission access through new MEPCO line.	1,526
10. HQ and three NE entities provided firm transmission access through two new lines.	1,446

Source: See Table B.1 in Appendix B for assumptions used in each calculation.

Increasing the number of generators located within northern Maine, by itself, will not be sufficient to reduce the current levels of market concentration (Scenarios 1, 2, and 3).[21] In addition, this approach would not enable customers in northern Maine to participate in a competitive wholesale electricity market.

Providing firm transmission access to at least two new competitive generation companies through the NBP transmission system could, in theory, reduce NBP's market share down to acceptable levels (i.e., our Scenarios 5 and 6). However, we do not see this as a practical approach, because of (a) NBP's high transmission tariff, (b) Hydro-Québec's unwillingness to use NBP's lines, (c) other generation companies' unwillingness to use NBP's lines, (d) the need to reserve back-up power from NBP, and (e) NBP's influence over the back-up power available. In addition, this scenario does not enable customers in northern Maine to participate in a competitive wholesale electricity market. Furthermore, it appears as though the Commission has insufficient leverage with NBP or the New Brunswick government to make this scenario a reality.

[21] Unless it were practical to site a new generation facility within northern Maine.

Finally, that leaves the option of building new transmission lines into northern Maine. The HHI for Scenario 7 indicates that a single transmission line utilized by a single party will not be enough to reduce market concentrations down to acceptable levels. Any new transmission line should be shared by at least two parties (as in Scenarios 8, 9 and 10).

It seems highly unlikely that the electricity market in northern Maine is large enough to support two new transmission lines. In fact, given that the area currently has sufficient transmission capacity for reliability purposes, the economics of even a single new transmission line are speculative. The Hydro-Québec transmission line appears to be more expensive than the New England line. In addition, the transmission line to New England is the only option that would allow customers in northern Maine to participate in a competitive wholesale electricity market. Consequently, we see Scenarios 8 and 9 as the most practical and most effective approach to reducing market power in northern Maine.

It is important to emphasize that we do not recommend that the HHI results here (or any HHI results) be used in isolation as firm indications of whether market power will be a problem in northern Maine. Herfindahl-Hirschman Indices are only rough illustrations of relative market concentration -- they do not account for a number of factors that can influence market power in the electricity industry in general, and they do not account for many of the key factors that lead to market power problems in northern Maine. Given the unique conditions in northern Maine, a scenario that results in an HHI of 1,700, for example, does not provide a great deal of assurance that there will not be market power problems in the region. The HHIs simply help provide an indication of which scenarios are likely to provide more market power relief than others.

7.2 Recommendations

Given the significance of the market power problem in northern Maine, we recommend that the Commission address the issue from a number of angles. The overarching goals of the Commission should be twofold: (1) to encourage the distribution companies within northern Maine to join the competitive wholesale electricity market in New England, and (2) to reduce the influence of NBP over the transmission of power into northern Maine. To help achieve these goals, we recommend the following specific actions:

1. Conduct further research. There are a number of areas where further research will shed light on some important issues raised in our study. For example, the Commission should:

    - Require MPS to conduct a thorough review of the costs and benefits of joining ISO-NE. The review should account for the benefits of reducing market power concerns in northern Maine.

    - Review TransEnergy's study of constructing a transmission line from Hydro-Québec to MPS. An initial draft of the study is due to be completed soon.

    - Periodically review the developments of the Northern Maine Working Group on Settlement, to determine the extent to which this route will increase competition in the wholesale electricity market in northern Maine.

- Urge MEPCO to study of the economic and business potential of constructing a new transmission line from MEPCO to MPS.

2. Use whatever political leverage is available to encourage NBP to provide truly non-discriminatory, open-access transmission service. One reasonable approach would be to request NBP to file its open-access transmission tariff with FERC. Another is to request NBP to remove the discrepancy between its wheel-through and wheel-out transmission prices.

3. To the extent that the previous option is unsuccessful, the Commission should encourage the investigation of a new transmission line between New England and MPS. The Commission should begin discussions with MPS, CMP, BHE, and MEPCO to investigate the advantages and disadvantages of constructing such a line, as well as who would act as project developer for the line.

4. Encourage the distribution companies in northern Maine to join the ISO-NE. This initiative may depend upon the outcomes of the previous two options.

5. Require MPS to adopt similar market power monitoring and prevention mechanisms as available through the ISO-NE, unless and until the distribution companies in northern Maine join the ISO-NE.

7.3 The Costs and Benefits of Addressing Market Power in Northern Maine.

Our conclusion that there is likely to be significant market power concerns in northern Maine for the foreseeable future raises two critical questions for the Commission:

- Are the negative implications of market power in northern Maine likely to be so great that the Commission should not open that market up to retail competition?

- If the Commission does open the northern Maine market up to retail competition, are the costs associated with the market power mitigation measures worth the benefits enjoyed in terms of reduced market power?

The first question is difficult to answer. It requires a comparison of (a) the benefits of retail competition relative to continued regulation, with (b) an estimate of the increase in electricity costs that northern Maine customers are likely to experience as a result of market power. The benefits of retail competition are speculative and depend upon a variety of factors that are difficult to anticipate. An estimate of the likely price increase resulting from market power is beyond the scope of this study. At this time, all we can safely say is that if retail competition is introduced in northern Maine without substantial changes to the current make up of market players, electricity customers are likely to pay prices that are significantly higher than those available from a competitive electricity market.

The second question may be a little easier to answer -- with additional information. The only two measures discussed above that are likely to require significant costs are the new transmission lines between MPS and Hydro-Québec or New England, and joining ISO-NE. The Commission should be able to access the on-going Hydro-Québec study regarding a new transmission line connection with MPS. A new study of the costs and

benefits of joining ISO-NE, and a new study of the costs of a new transmission link between NEPOOL and MPS, would provide important information regarding the advantage of those options relative to the disadvantages of market power in northern Maine. Such studies would be essential in answering the second question raised above.

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Appendix A. Map of Northern Maine and Regional Interconnections

A map of northern Maine and interconnections with utilities in the region is attached. This map is taken directly from Exhibit BLB II-1 of Bustard, Louridas and Brown 1998.

Appendix B. Herfindahl-Hirschman Index Calculations

Table B.1 HHI Analysis of Various Scenarios Addressing Market Power.

Owner	Power Source	Total Capacity (mw)	Share of Total Capacity	HHI
1. Before MPS Divestiture				
MPS	Hydro - Tinker	33.5	15%	----
MPS	Other (Hydro, Diesels)	14.6	6%	----
MPS	Wheelabrator - Sherman	18.1	8%	----
MPS Total	**----**	66.2	29%	864
AVEC	Wood	32.0	14%	202
AEI	Wood	37.0	16%	270
NBP	Imports	90.0	40%	1,597
Total	**----**	**225.2**	**100%**	**2,933**
2. After MPS Divestiture: Two Buyers				
Buyer 1	Hydro - Tinker	33.5	15%	----
Buyer1	Other (Hydro, Diesels)	14.6	6%	----
Buyer 1 Total	**----**	48.1	21%	456
Buyer 2	Wheelabrator - Sherman	18.1	8%	----
AVEC	Wood	32.0	14%	202
AEI	Wood	37.0	16%	270
NBP	Imports	90.0	40%	1,597
Total	**----**	**225.2**	**100%**	**2,525**
3. After MPS Divestiture: Three Buyers				
Buyer 1	Hydro - Tinker	33.5	15%	221
Buyer 2	Other (Hydro, Diesels)	14.6	6%	42
Buyer 3	Wheelabrator - Sherman	18.1	8%	65
AVEC	Wood	32.0	14%	202
AEI	Wood	37.0	16%	270
NBP	Imports	90.0	40%	1,597
Total	**----**	**225.2**	**100%**	**2,397**
4. HQ Provided Firm Transmission Access Through NBP				
WPS	Hydro - Tinker	33.5	15%	----
WPS	Other (Hydro, Diesels)	14.6	6%	----
WPS Total	**----**	48.1	21%	456
Buyer 2	Wheelabrator - Sherman	18.1	8%	----
AVEC	Wood	32.0	14%	202
AEI	Wood	37.0	16%	270
NBP	Imports	45.0	20%	399
HQ	Imports	45.0	20%	399
Total	**----**	**225.2**	**100%**	**1,727**
5. Two NEPOOL Entities Provided Firm Transmission Access Through NBP				
WPS	Hydro - Tinker	33.5	15%	----
WPS	Other (Hydro, Diesels)	14.6	6%	----
WPS Total	**----**	48.1	21%	456
Buyer 2	Wheelabrator - Sherman	18.1	8%	----
AVEC	Wood	32.0	14%	202
AEI	Wood	37.0	16%	270
NBP	Imports	45.0	20%	399
NEPOOL	Imports	22.5	10%	100
NEPOOL	Imports	22.5	10%	100
Total	**----**	**225.2**	**100%**	**1,527**

Table B.1 Continued

6. Three NEPOOL Entities Provided Firm Transmission Access Through NBP

WPS	Hydro - Tinker	33.5	15%	----
WPS	Other (Hydro, Diesels)	~~14.6~~	~~6%~~	----
WPS Total	**----**	48.1	21%	456
Buyer 2	Wheelabrator - Sherman	18.1	8%	----
AVEC	Wood	32.0	14%	202
AEI	Wood	37.0	16%	270
NBP	Imports	45.0	20%	399
NEPOOL	Imports	15.0	7%	44
NEPOOL	Imports	15.0	7%	44
NEPOOL	Imports	15.0	7%	44
Total	**----**	**225.2**	**100%**	**1,460**

7. HQ Provided Firm Access Through New 100 mw HQ/MPS Transmission Line

WPS	Hydro - Tinker	33.5	10%	----
WPS	Other (Hydro, Diesels)	~~14.6~~	~~4%~~	----
WPS Total	**----**	48.1	15%	219
Buyer 2	Wheelabrator - Sherman	18.1	6%	----
AVEC	Wood	32.0	10%	97
AEI	Wood	37.0	11%	129
NBP	Imports	90.0	28%	766
HQ	Imports	100.0	31%	946
Total	**----**	**325.2**	**100%**	**2,157**

8. Two NEPOOL Entities Provided Firm Access Through New 100 mw MEPCO Line

WPS	Hydro - Tinker	33.5	10%	----
WPS	Other (Hydro, Diesels)	~~14.6~~	~~4%~~	----
WPS Total	**----**	48.1	15%	219
Buyer 2	Wheelabrator - Sherman	18.1	6%	----
AVEC	Wood	32.0	10%	97
AEI	Wood	37.0	11%	129
NBP	Imports	90.0	28%	766
NEPOOL	Imports	50.0	15%	236
NEPOOL	Imports	50.0	15%	236
Total	**----**	**325.2**	**100%**	**1,684**

9. Three NEPOOL Entities Provided Firm Access Through New 100 mw MEPCO Line

WPS	Hydro - Tinker	33.5	10%	----
WPS	Other (Hydro, Diesels)	~~14.6~~	~~4%~~	----
WPS Total	**----**	48.1	15%	219
Buyer 2	Wheelabrator - Sherman	18.1	6%	----
AVEC	Wood	32.0	10%	97
AEI	Wood	37.0	11%	129
NBP	Imports	90.0	28%	766
NEPOOL	Imports	33.3	10%	105
NEPOOL	Imports	33.3	10%	105
NEPOOL	Imports	33.3	10%	105
Total	**----**	**325.2**	**100%**	**1,526**

10. HQ and Three NEPOOL Entities Provided Firm Access Through Two New Lines

WPS	Hydro - Tinker	33.5	8%	----
WPS	Other (Hydro, Diesels)	~~14.6~~	~~3%~~	----
WPS Total	**----**	48.1	11%	128
Buyer 2	Wheelabrator - Sherman	18.1	4%	----
AVEC	Wood	32.0	8%	57
AEI	Wood	37.0	9%	76
NBP	Imports	90.0	21%	448
HQ	Imports	100.0	24%	553
NEPOOL	Imports	33.3	8%	61
NEPOOL	Imports	33.3	8%	61
NEPOOL	Imports	33.3	8%	61
Total	**----**	**425.2**	**100%**	**1,446**

Table B.2 HHI Analysis -- Assuming That NBP Can Use 200 MW of Transmission Capacity

Owner	Power Source	Total Capacity (mw)	Share of Total Capacity	HHI
1. Before MPS Divestiture				
MPS	Hydro - Tinker	33.5	10%	----
MPS	Other (Hydro, Diesels)	14.6	4%	----
MPS	Wheelabrator - Sherman	18.1	5%	----
MPS Total	**----**	66.2	20%	390
AVEC	Wood	32.0	10%	91
AEI	Wood	37.0	11%	122
NBP	Imports	200.0	60%	3,560
Total	**----**	**335.2**	**100%**	**4,163**
2. After MPS Divestiture: Two Buyers				
Buyer 1	Hydro - Tinker	33.5	10%	----
Buyer1	Other (Hydro, Diesels)	14.6	4%	----
Buyer 1 Total	**----**	48.1	14%	206
Buyer 2	Wheelabrator - Sherman	18.1	5%	----
AVEC	Wood	32.0	10%	91
AEI	Wood	37.0	11%	122
NBP	Imports	200.0	60%	3,560
Total	**----**	**335.2**	**100%**	**3,979**
3. After MPS Divestiture: Three Buyers				
Buyer 1	Hydro - Tinker	33.5	10%	100
Buyer 2	Other (Hydro, Diesels)	14.6	4%	19
Buyer 3	Wheelabrator - Sherman	18.1	5%	29
AVEC	Wood	32.0	10%	91
AEI	Wood	37.0	11%	122
NBP	Imports	200.0	60%	3,560
Total	**----**	**335.2**	**100%**	**3,921**
4. HQ Provided Firm Transmission Access Through NBP				
WPS	Hydro - Tinker	33.5	10%	----
WPS	Other (Hydro, Diesels)	14.6	4%	----
WPS Total	**----**	48.1	14%	206
Buyer 2	Wheelabrator - Sherman	18.1	5%	----
AVEC	Wood	32.0	10%	91
AEI	Wood	37.0	11%	122
NBP	Imports	100.0	30%	890
HQ	Imports	100.0	30%	890
Total	**----**	**335.2**	**100%**	**2,199**
5. Two NEPOOL Entities Provided Firm Transmission Access Through NBP				
WPS	Hydro - Tinker	33.5	10%	----
WPS	Other (Hydro, Diesels)	14.6	4%	----
WPS Total	**----**	48.1	14%	206
Buyer 2	Wheelabrator - Sherman	18.1	5%	----
AVEC	Wood	32.0	10%	91
AEI	Wood	37.0	11%	122
NBP	Imports	100.0	30%	890
NEPOOL	Imports	50.0	15%	223
NEPOOL	Imports	50.0	15%	223
Total	**----**	**335.2**	**100%**	**1,754**

Table B.2 Continued

6. Three NEPOOL Entities Provided Firm Transmission Access Through NBP

WPS	Hydro - Tinker	33.5	10%	----
WPS	Other (Hydro, Diesels)	~~14.6~~	~~4%~~	----
WPS Total	**----**	48.1	14%	206
Buyer 2	Wheelabrator - Sherman	18.1	5%	----
AVEC	Wood	32.0	10%	91
AEI	Wood	37.0	11%	122
NBP	Imports	100.0	30%	890
NEPOOL	Imports	33.3	10%	99
NEPOOL	Imports	33.3	10%	99
NEPOOL	Imports	33.3	10%	99
Total	**----**	**335.2**	**100%**	**1,606**

7. HQ Provided Firm Access Through New 100 mw HQ/MPS Transmission Line

WPS	Hydro - Tinker	33.5	8%	----
WPS	Other (Hydro, Diesels)	~~14.6~~	~~3%~~	----
WPS Total	**----**	48.1	11%	122
Buyer 2	Wheelabrator - Sherman	18.1	4%	----
AVEC	Wood	32.0	7%	54
AEI	Wood	37.0	9%	72
NBP	Imports	200.0	46%	2,112
HQ	Imports	100.0	23%	528
Total	**----**	**435.2**	**100%**	**2,888**

8. Two NEPOOL Entities Provided Firm Access Through New 100 mw MEPCO Line

WPS	Hydro - Tinker	33.5	8%	----
WPS	Other (Hydro, Diesels)	~~14.6~~	~~3%~~	----
WPS Total	**----**	48.1	11%	122
Buyer 2	Wheelabrator - Sherman	18.1	4%	----
AVEC	Wood	32.0	7%	54
AEI	Wood	37.0	9%	72
NBP	Imports	200.0	46%	2,112
NEPOOL	Imports	50.0	11%	132
NEPOOL	Imports	50.0	11%	132
Total	**----**	**435.2**	**100%**	**2,624**

9. Three NEPOOL Entities Provided Firm Access Through New 100 mw MEPCO Line

WPS	Hydro - Tinker	33.5	8%	----
WPS	Other (Hydro, Diesels)	~~14.6~~	~~3%~~	----
WPS Total	**----**	48.1	11%	122
Buyer 2	Wheelabrator - Sherman	18.1	4%	----
AVEC	Wood	32.0	7%	54
AEI	Wood	37.0	9%	72
NBP	Imports	200.0	46%	2,112
NEPOOL	Imports	33.3	8%	59
NEPOOL	Imports	33.3	8%	59
NEPOOL	Imports	33.3	8%	59
Total	**----**	**435.2**	**100%**	**2,537**

10. HQ and Three NEPOOL Entities Provided Firm Access Through Two New Lines

WPS	Hydro - Tinker	33.5	6%	----
WPS	Other (Hydro, Diesels)	~~14.6~~	~~3%~~	----
WPS Total	**----**	48.1	9%	81
Buyer 2	Wheelabrator - Sherman	18.1	3%	----
AVEC	Wood	32.0	6%	36
AEI	Wood	37.0	7%	48
NBP	Imports	200.0	37%	1,397
HQ	Imports	100.0	19%	349
NEPOOL	Imports	33.3	6%	39
NEPOOL	Imports	33.3	6%	39
NEPOOL	Imports	33.3	6%	39
Total	**----**	**535.2**	**100%**	**2,026**

Appendix C. Transmission Cost Estimates

Figure 1 shows a single-line diagram of the proposed Haynesville-Mullen interconnection, which consists of the following facilities:

(1) An extension to Mullen substation containing:

- One 138-kV and one 69-kV circuit breaker
- One 69/138-kV transformer

(2) A 138-kV Mullen-Haynesville transmission line of about 25 miles

(3) A substation at Haynesville containing:

- A 345-kV bus
- Three 345-kV and one 138-kV circuit breakers
- A 138/345-kV transformer

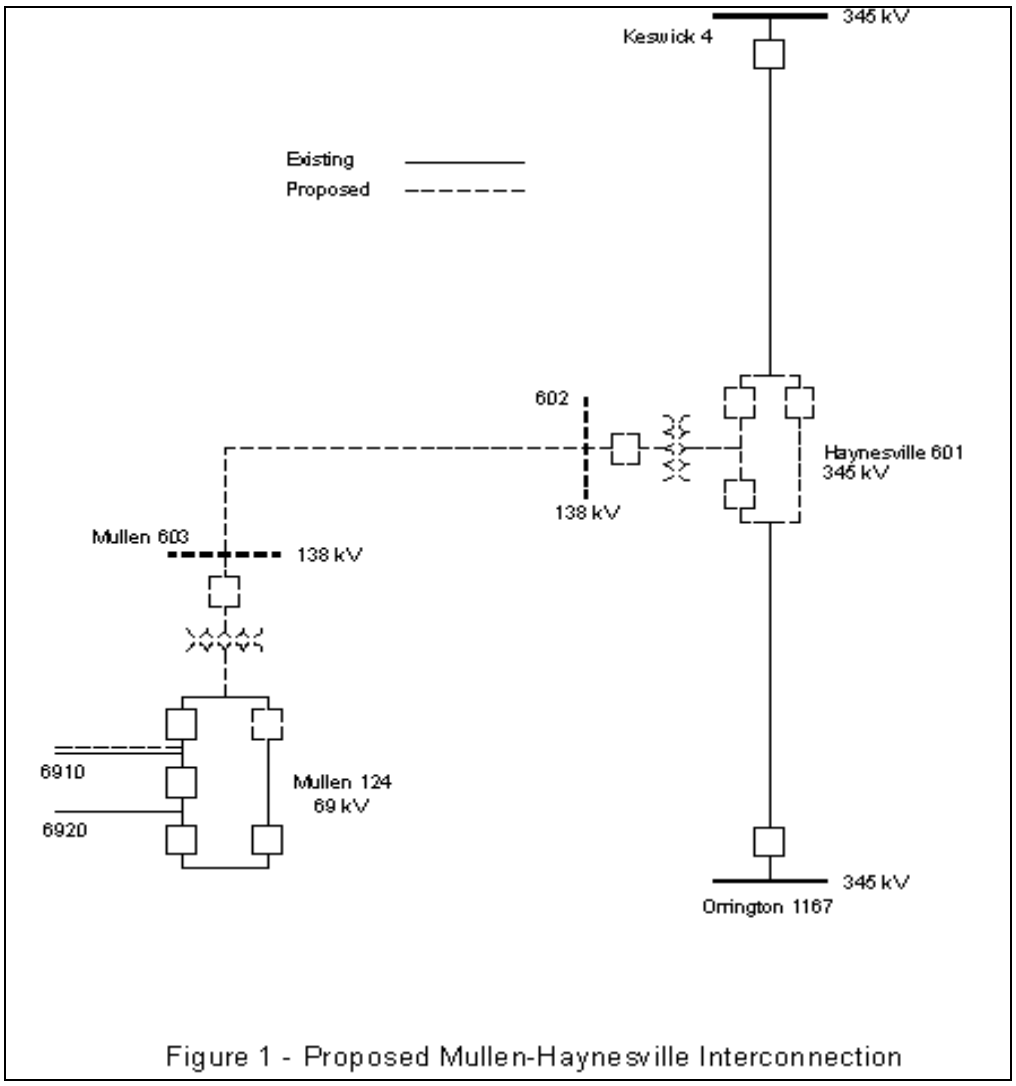

Figure 1 - Proposed Mullen-Haynesville Interconnection

Figure 2 below shows the transmission line configuration selected for the cost estimate: a 138-kV shielded single-circuit line, H-frame wood-pole construction.

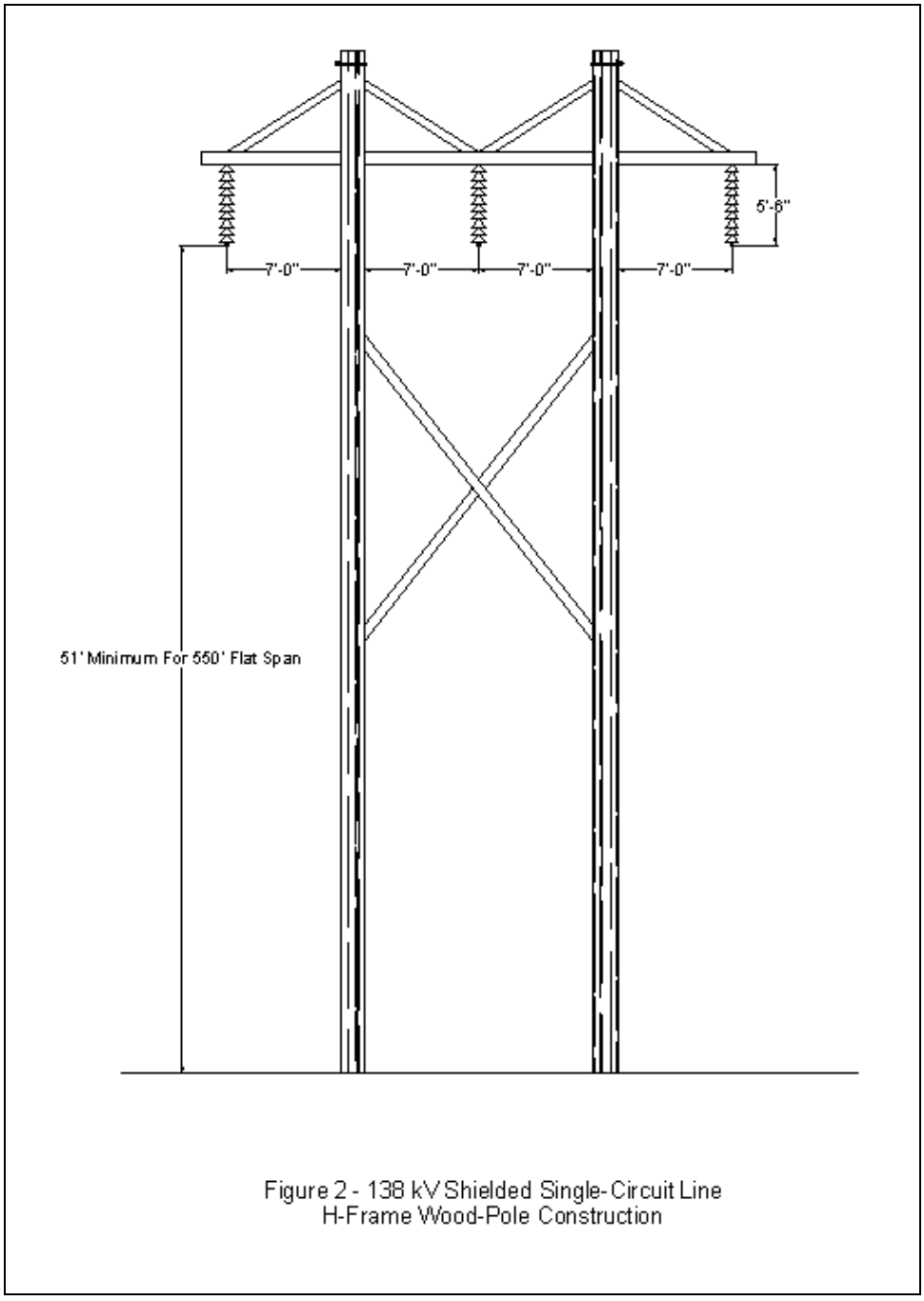

Figure 2 - 138 kV Shielded Single-Circuit Line
H-Frame Wood-Pole Construction

Table C.1 gives the construction cost estimate for the proposed Haynesville-Mullen interconnection. The construction cost estimate is $13.6 million for Stage 1, and $15.5 million for Stage 2, leading to a total cost of $29.1 million.

Table C.1 Construction Cost Estimate – Proposed Haynesville-Mullen Interconnection

Stage 1	Cost
Extension to the Mullen Substation	$1,030,000.
25-mile 138-kV line ($356K/mile)	$8,936,780.
Haynesville Substation	$3,550,000.
Regulatory Cost	$118,000.
Subtotal – Stage 1	$13,634,780.
Stage 2 (rebuild of Line 6910)	
42-mile 138-kV line ($356K/mile)	$14,669,136.
Mullen termination	$365,000.
Flo's Inn termination	$430,000.
Regulatory Cost & Permit Fees	$50,000.
Subtotal – Stage 2	$15,514,136.
TOTAL	$29,148,916.

Table C.2 gives the construction cost estimate per mile for the proposed 138-kV line. This estimate is based on the estimate given in the Acres report for a 115-kV single-circuit, overhead, H-frame, wood-pole transmission line (Acres 1996). Cost estimates in the Acres report have been updated in Table C.2 for 138-kV construction. As shown, the cost is $356,047 per mile, excluding the cost for purchasing right-of-way. Table C.3 gives construction cost estimates for the substations at Haynesville, Mullen, and Flo's Inn. Sample material costs are given in Table C.4.

Table C.2 Construction Cost Estimate

138-kV Single-Circuit Overhead Transmission Line Shielded H-Frame Wood-Pole Construction

Line Cost Per Mile, Excluding Right-of-Way Purchase

				Unit Cost			
			Unit Cost	Mat'l. &	Total Cost		
Civil Work	Quantity	Unit	Labor	Equip	Labor	Material	Total
R-O-W Clearing	6.06	acre	$3,500.	$5,000.	$21,215.	$30,307.	$51,522.
Access road	1800		$2	$2	$3,600.	$3,600.	$7,200.
Structure erection: Wooden H-frames	9.6	Ea	$7,560.		$72,576.		$72,576.
Structure grounding	9.6	Ea	$300.		$2,880.		$2,880.
Guying	4	Ea	$900.		$3,600.		$3,600.
Stringing	8.6	Span	$3,630.		$31,218.		$31,218.
Police							
Overtime							
Sub-total							**$168,996.**
Overhead line							
Conductor – 795 kcmil ACSR (DRAKE)	16,650	Ft.		$1.33		$22,145.	$22,145.
Shield wire – 7 No. 7 Alumoweld	11,100	Ft.		$0.30		$3,300.	$3,300.
Insulators & hardwares:							
-5 feet long suspension insulator	28.8	Ea		$278.		$8,014.	$8,014.
Shield wire support arm							
Structure supply:							
-Wooden H-Frame: Tangent	7.6	Ea		$5,144.		$39,094.	$39,094.
-Wooden H-Frame: Angle	1	Ea		$5,656.		$5,656.	$5,656.
-Wooden H-Frame: Dead End	1	Ea		$6,008.		$6,008.	$6,008.
Material handling & storage	15%	lot				$12,633.	$12,633.
Sub-total							**$96,850.**
Administration	2%	Lot					$5,317.
Engineering & supervision	11.5%	Lot					$30,572.
AFUDC	3%	Lot					$9,052.
Contingency	15%	Lot					$45,260.
Total Line Cost (Per Mile)							**$356,047.**
Terminal Cost – Per Project							
Terminal structures:	2	Ea	$3,896.	$6,007.	$7,792.	$12,014.	$19,806.
Testing & commissioning	1	Lot	$10,000.		$10,000.		$10,000.
Material handling & storage	15%	Lot				$1,802.	$1,802.
Sub-total							**$31,608.**
Administration	2%	Lot					$632.
Engineering & supervision	11.5%	Lot					$3,635.
AFUDC	3%	Lot					$1,076.
Contingency	15%	Lot					$5,381.
Total Terminal Cost							**$42,332.**

Regulatory Cost & Permit Fees – Per Project							
Regulatory cost & permit fees		Lot					$100,000.
AFUDC	3%	Lot					$3,000.
Contingency	15%	Lot					$15,000.
Total Fees							**$118,000.**

Table C.3 Construction Cost Estimate – Substations

1. Stage 1	Cost
1.1. Haynesville	
Civil Works – Land Improvement	$200,000.
Structures (Line Terminal, Bus)	$100,000.
Autotransformer (150 MVA)	$2,000,000.
Circuit Breakers (three 345-kV, one 138-kV)	$750,000.
General Equipment & Apparatus	$500,000.
Subtotal - Haynesville	$3,550,000.
1.2. Mullen	
Civil Works – Land Improvement	$50,000.
Structures (Line Terminal)	$30,000.
Autotransformer (50 MVA)	$750,000.
Circuit Breakers (one 138-kV, one 69-kV)	$100,000.
General Equipment & Apparatus	$100,000.
Subtotal - Mullen	$1,030,000.
2. Stage 2 (Rebuild Line 6910)	
2.1. Mullen	
Civil Works – Land Improvement	$50,000.
Structures (Line Terminal, Bus)	$90,000.
Circuit Breakers (two 138-kV)	$125,000.
General Apparatus & Equipment	$100,000.
Subtotal - Mullen	$365,000.
2.2. Flo's Inn	
Civil Works – Land Improvement	$50,000.
Structures (Line Terminal, Bus)	$90,000.
Circuit Breakers (three 138-kV)	$190,000.
General Apparatus & Equipment	$100,000.
Subtotal – Flo's Inn	$430,000.

Table C.4 Sample Material Costs – 1998

Item	Supplier	Unit Cost
1. Wood Pole	Koppers Industries	
1.1 55' – Class 1	436 Seventh Avenue	$755.
1.2 65' – Class 1	Pittsburgh, PA 15219	$1,201.
1.3 70' – Class 1	Tel. 412-227-2416	$1,470.
2. Wood Crossarm	Hughes Brothers	
Double crossarm	210 N. 13th Street	$774.
3-5/8" x 8-1/2" solid sawn	Seward, NE 68434	
	Tel. 402-643-2991	
Cross brace	Hughes Brothers	
X brace	210 N. 13th Street	$327.
Pair of Vee braces	Seward, NE 68434	$185.
	Tel. 402-643-2991	
4. Conductor	BICC Cables Co.	
4.1 ACSR Drake (759 kcmil)	One Crosfield Avenue	$1.10/ft
4.2 ACSR Partridge (267 kcmil)	West Nyack, NY 10994	$0.44/ft
	Tel. 800-237-2726	
4.3 Copperweld (No. 8)	BRIM Electronics Inc.	$0.14/ft.
	120 Home Place	
	Lodi, NJ 07644	
	Tel. 201-796-2886	
5. Insulator	LAPP Insulator Co.	$134.
Suspension string:	130 Gilbert Street	
Ten 10-inch standard	Leroy, NY 14482	
Porcelain discs	Tel. 716-768-6221	
6. Autotransformer	ABB Power T&D Co.	
6.1 138/69kV-100 MVA	125 Theobold Avenue	$1,155,000.
6.2 138/69kV-200 MVA	Greensburg, PA 15601	$1,634,000.
6.3 138/345kV-100 MVA	Tel. 724-838-5215	$1,482,000.
6.4 138/345kV-200 MVA		$2,700,000.
7. Circuit Breaker	GEC Alsthom	
7.1 69kV, 1800A, 40kA	4 Skyline Drive	$35,000.
7.2 138kV, 1200A, 20kA	Hawthorne, NY	$52,000.
7.3 345kV, 2000A, 40kA	Tel. 914-347-5177	$205,000.